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Petroleum Fugitive Emissions --Background Information for Promulgated Standards

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Research Triangle Park, NC

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15. SUPPLEMENTARY NOTES This document presents the background information used by the Environmental Protection Agency in developing the promulgated new source performance standards for equipment of VOC in the petroleum refining industry.

16. ABSTRACT

Standards of performance for the control of volatile organic compound (VOC) equipment leaks from the petroleum refining industry are bing promulgated under Section 111 of the Clean Air Act. These standards will apply to equipment leaks of VOC within new, modified, and reconstructed petroleum refinery compressors and process units. This document summarizes the responses to public comments received on the proposed standards and the basis for changes made in the standards since proposal.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
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Petroleum Fugitive Emissions— Background Information for Promulgated Standards

Emission Standards and Engineering Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air, Noise, and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

October 1983

i.a

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ENVIRONMENTAL PROTECTION AGENCY

Background Information and Final Environmental Impact Statement for Equipment Leaks of VOC in Petroleum Refineries

Prepared by:

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1. The promulgated standards of performance will limit emissions of VOC from equipment leaks in new, modified, and reconstructed petroleum refinery process units and compressors. Section 111 of the Clean Air Act (42 U.S.C. 7411), as amended, directs the Administrator to establish standards of performance for any category of new stationary source of air pollution that". . . causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

2. Copies of this document have been sent to the following Federal Departments: Labor, Health and Human Services, Defense, Transportation, Agriculture, Commerce, Interior, and Energy; the National Science Foundation; the Council on Environmental Quality; State and Territorial Pollution Program Administrators; EPA Regional Administrators; Local Air Pollution Control Officials; Office of Management and Budget; and other interested parties.

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1.0 SUMMARY

On January 4, 1983, the U.S. Environmental Protection Agency (EPA) proposed standards of performance for fugitive emission sources of volatile organic compounds (VOC) in the petroleum refining industry (48 FR 279) under the authority of Section 111 of the Clean Air Act. Public comments were requested on the proposed standards in the Federal Register, and 24 commenters responded. Most of the commenters represented refining companies or industry associations. Other commenters included an environmental group, the Department of the Interior, and vendors of equipment used to control fugitive emissions. This summary of comments and EPA's responses to these comments serve as the basis for the revisions made to the applicability and the requirements of the proposed standards.

1.1 SUMMARY OF CHANGES SINCE PROPOSAL

The proposed standards were revised as a result of reviewing public comments. The major revisions concern the following:

- Leak Detection and Repair for Refineries Located in the North Slope of Alaska
- Alternative for Determining a "Capital Expenditure"
- Clarification of Reconstruction Provisions
- Provision for Difficult-to-Monitor Valves in New Units
- Exemptions for Compressors
- Addition of Reporting Requirements
- Open-ended Lines on Double Block and Bleed Valves

1.1.1 Leak Detection and Repair for Refineries Located in the North Slope of Alaska

Since proposal, EPA has reviewed comments concerning refining operations in the North Slope of Alaska and determined that the costs to comply with certain aspects of the proposed standards can be unreasonable. Leak detection and repair programs incur higher labor, administrative, and support costs at plants that are located at great distances from major population centers and particularly those that experience extremely low temperatures as in the arctic. Thus, EPA decided to exempt plants located in the North Slope of Alaska from the routine leak detection and repair requirements. EPA excluded these plants only from the routine leak detection and repair requirements because the costs of the other requirements are reasonable.

1.1.2 Alternative for Determining a "Capital Expenditure"

The General Provisions (Subpart A) of 40 CFR Part 60, require that increases in emissions of a pollutant covered by applicable standards trigger the application of standards of performance for existing facilities. These increases make a source covered by standards a modified source, as set forth in Section 111 of the Act. EPA has interpreted Section 111 so that production rate increases accomplished without a capital expenditure do not trigger these provisions even though they might be accompanied by an increase in emissions (See 40 CFR 60.14(e)(2)) Capital expenditure is defined in 40 CFR 60.2. In the proposed standards, EPA also excluded increases in emissions resulting from process improvements accomplished without a capital expenditure from being considered a modification. The intent was to exclude minor changes in operations as indicated by changes not accompanied by a capital expenditure.

The annual asset guideline repair allowance (AAGRA) and the original cost basis are used to define capital expenditure (see 40 CFR 60.2). The definition of AAGRA is specified by the Internal Revenue Service (IRS) and its use has not changed despite tax law changes in 1982. In response to the comments concerning the difficulties of using the AAGRA and the original cost basis, EPA is providing in the standards for equipment leaks an alternative procedure for determining capital expenditure. The purpose of the alternative is to make the determination of capital expenditure more practicable, yet maintain the original intent of the definition. This alternative provides that a capital expenditure would be incurred if actual costs exceed the product, P, of the existing facility's (that is, the equipment covered by the standards) replacement cost A, the AAGRA basis and an inflation factor, Y, as shown in the following equation:

$P = A \times Y \times 0.07$, where
A = existing facility replacement cost,
Y = the percent of the present replacement cost which is equivalent to the original cost,
$= 1.0 - 0.575 \log (X)$, and
X = the year of construction.

1.1.3 Clarification of Reconstruction Provisions

The provisions for reconstruction (40 CFR 60.15) imply that costs are accumulated over an unlimited time period. Commenters, however, objected to a continuous accumulation of costs because refineries are continually replacing components. To clarify the application of Section 60.15, EPA is defining "proposed replacement" under this standard to include components which are replaced pursuant to all continuous programs of component replacement which commence (but are not necessarily completed) within a 2-year period. Thus, EPA will count toward the 50 percent reconstruction threshold the "fixed capital cost" of all depreciable components replaced pursuant to all continuous programs of reconstruction which commmence within any 2-year period following proposal of these standards.

EPA is further clarifying the intent of the reconstruction provisions based on comments concerning routine equipment replacement. In response to these comments, EPA is clarifying that certain routine replacements are not considered in the basis for reconstruction. The routine replacements excluded by the final standards from reconstruction are valve packings, pump seals, nuts and bolts, and rupture disks. Replacement of equipment pieces, such as valves and pumps, at turnaround or at other times must be included when considering whether a reconstruction will take place.

1.1.4 Provision for Difficult-to-Monitor Valves in New Units

At proposal, there was no exemption for difficult-to-monitor valves in new units, although difficult-to-monitor valves were exempt from routine monitoring in units covered through the modification or reconstruction provisions. Commenters argued that while the number of difficult-to-monitor valves can be substantially reduced in number for new units, they cannot be totally eliminated. Upon reviewing the comment letters, EPA decided to permit an allowable percentage of valves in a new unit to be designated as difficult-to-monitor. Based on existing units, about 3 percent of the total number of valves may be impossible to eliminate without additional costs. Therefore, EPA is allowing up to 3 percent of total numbers of valves to be treated as difficult-to-monitor valves for new units.

1.1.5 Exemptions for Compressors

Commenters were concerned that process streams with a high hydrogen content would be subject to the standards. The commenters contended that such streams would have a lower percentage of VOC and, consequently, the controls required by the proposed standards would achieve lower emission reductions and have a higher cost effectiveness ($/Mg of VOC emission reduction).

Upon analyzing the cost effectiveness of valves and compressors in hydrogen service (greater than 50 volume percent hydrogen) (Document Reference No. IV-B-9), EPA determined that significant emission reductions are achieved for valves in hydrogen service at a reasonable cost ($106/Mg VOC). However, control of compressors in hydrogen service results in a cost effectiveness of $4,600/Mg VOC. EPA, therefore, decided to exempt these compressors from the standards.

Commenters also implied that EPA had provided an exemption from the standards for existing compressors. EPA provided no blanket exemption in the proposed standards even though EPA discussed that certain reciprocating compressors might not be covered under the reconstruction provisions if retrofitting the required equipment was technologically or economically infeasible (See 40 CFR 60.15(e)). To make EPA's intent clear and to reduce the burden of reviewing reconstruction determinations, EPA is explicitly exempting reciprocating compressors that become affected by the standards through 40 CFR 60.14 or 60.15 from the standards for compressors provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance. If an owner or operator is replacing a compressor or recasting the distance piece for some other reason than to reduce emissions and comply with the standards or if these actions occur later, then a modified or reconstructed compressor would not be exempt from the standards.

1.1.6 Addition of Reporting Requirements

The proposed standards did not require routine reporting. The preamble to the proposed standards addressed three alternative levels of reporting requirements. The alternative of no routine reporting was selected because State or local agencies, who usually are delegated the responsibility for enforcement of the standards, could require routine reporting.

In response to comments on the enforceability of the standards and comments on the need for routine reporting, EPA decided to require routine reporting in these standards of performance rather than relying on individual State requirements. Compliance with the leak detection and repair program and equipment requirements will be assessed through semiannual reports, review of records, and by inspection. The semiannual reports provide a summary of the data recorded on leak detection and repair of valves, pumps, and other equipment types. Notifications are still required as described in the General Provisions for new source standards (40 CFR 60.7). However, the semiannual reports may be waived for affected facilities in States where the regulatory program has been delegated, if EPA, in the course of delegating such authority, approves reporting requirements or an alternative means of source surveillance adopted by the State. In these cases, such sources would be required to comply with the requirements adopted by the State.

1.1.7 Open-Ended Lines on Double Block and Bleed Valves

The proposed standards required all open-ended lines or valves to be capped except when they are being used. In some cases, however, open-ended valves are installed in a "double block-and-bleed" arrangement such that emissions must occur to the atmosphere through the open end of the bleed valve. In such cases, the open end of the bleed valve was not required to be capped because they are used to vent the line between the block valves. However, when the bleed valve is not open, then it must be capped. This was not as clear as it could have been in the proposed standards and, therefore, a specific provision has been added to the standards.

1.2 SUMMARY OF IMPACTS OF PROMULGATED ACTION

1.2.1 Alternatives to Promulgated Action

The regulatory alternatives discussed in Chapter 6 of the BID for the proposed standards generally reflect the different levels of emission control. They were used to help in selection of the best demonstrated technology, considering costs and nonair quality health, environmental, and economic impacts for fugitive emission sources in the petroleum refining industry. These alternatives remain the same; however, the costs, emission reductions, cost effectiveness, and incremental cost effectiveness for the various levels of control included in the regulatory alternatives, which were estimated and then summarized in the preamble to the proposed standards, have been reevaluated and are now summarized on a per component basis as presented in Table 1-1. These estimates served as the basis for determining the impacts of the standards. Model Unit and nationwide impacts of the promulgated standards are documented in Appendix D.

1.2.2 Environmental Impacts of Promulgated Action

Environmental impacts of the proposed standards are described in 48 FR 279. The revisions to the applicability and provisions of the proposed standards (described in Section 1.1) will have a minimal effect on the environmental impacts of the standards.

1.2.3 Energy and Economic Impacts of Promulgated Action

The energy and economic impacts of the standards are described in Chapters 8 and 9 and Appendix F of the BID for the proposed standards. In general, there has been little change in these impacts since proposal.

The nationwide cost impacts reported in the preamble to the promulgated standards are lower than the impacts reported at proposal. At proposal, the nationwide cost impacts were based on refineries not subject to State or regional regulations to control equipment leaks of VOC. However, the nationwide impacts have subsequently been revised (as shown in Appendix D) based upon the baseline control costs to comply with existing regulations for equipment leaks of VOC.

1.2.4 Other Considerations

1.2.4.1 Irreversible and Irretrievable Commitment of Resources. Section 7.6.1 of the BID for the proposed standards concluded that the

Table 1-1. SUMMARY OF THE INDIVIDUAL COMPONENT CONTROL IMPACTS[a]

Fugitive Emission Source	Control Technique	Emission Reduction (Mg/yr)	Average Cost Effectiveness ($/Mg)[b]	Incremental Cost Effectiveness ($/Mg)[c]
Pressure relief devices	Quarterly LDR	4.4	(170)	(170)
	Monthly LDR	5.3	(110)	250
	Rupture disks[d]	9.8	410	1,000
Compressors	Controlled degassing vents	16.5	150	150
Open-ended valves	Caps on open ends	2.8	460	460
Sampling connection systems	Closed purge sampling	2.6	810	810
Valves	Quarterly LDR	66	(110)	(110)
	Monthly LDR	77	(60)	310
	Sealed bellows valves	110	4,700	16,700
Pumps	Annual LDR	3.0	860	860
	Quarterly LDR	9.8	157	(140)
	Monthly LDR	11.5	158	170
	Dual mechanical seal system	13.9	2,000	10,900

(xx) = Cost savings
LDR = Leak detection and repair

[a] Costs and emission reductions are based on fugitive emission component counts in Model B from the BID for the proposed standards, EPA-450/3-81-015a, page 6-3, and from Tables A-2 through A-13 of Appendix A.

[b] Average Cost Effectiveness = net annualized costs per component ÷ annual VOC emission reduction per component.

[c] Incremental Cost Effectiveness = (net annualized cost of the control technique - net annualized cost of the next less restrictive control technique) ÷ (annual emission reduction of control technique - annual emission reduction of the next less restrictive control technique).

[d] Underlined control techniques were selected as basis for standards.

standards will not result in any irreversible or irretrievable commitment of resources. It was also concluded that the standards should help to save resources due to the energy savings associated with the reduction in emissions. These conclusions remain unchanged since proposal.

1.2.4.2 Environmental and Energy Impacts of Delayed Standards. Table F-11 of the BID for the proposed standards summarizes the environmental and energy impacts associated with delaying promulgation of the standards. The emission reductions and associated energy savings shown would be irretrievably lost at the rates shown for each of the 5 years.

1.3 SUMMARY OF PUBLIC COMMENTS

Letters were received from 24 commenters commenting on the proposed standards and the BID for the proposed standards. There was one request for a public hearing, however, these commenters were requesting a meeting with EPA for clarification of the proposed standards. Minutes of this meeting are contained in the project docket. A list of commenters, their affiliations, and the EPA docket number assigned to their correspondence is given in Table 1-2.

The comments have been categorized under the following topics:

Standards (Section 2)
Applicability (Section 3)
Modification (Section 4)
Reconstruction (Section 5)
Legal (Section 6)
Test Methods (Section 7)
Recordkeeping and Reporting (Section 8)
Appendix A - Incremental Cost Effectiveness of Control Techniques for Equipment Leaks of VOC
Appendix B - Regulatory Decisions Affecting Standards for SOCMI
Appendix C - Evaluation of Available Equipment Leak Data

Appendix D - Model Unit and Nationwide Impacts

TABLE 1-2. LIST OF COMMENTERS ON PROPOSED STANDARDS OF PERFORMANCE FOR FUGITIVE EMISSION SOURCES IN THE PETROLEUM REFINING INDUSTRY

COMMENTER AND AFFILIATION	DOCKET ITEM NO.
1. Mr. B.T. McMillan Allied Chemical P.O. Box 1053R Morristown, NJ 07960	IV-D-3
2. Mr. C.H. Barre Marathon Petroleum Company Findlay, Ohio 45840	IV-D-4
3. Mr. R.E. Farrell Standard Oil Company of Ohio Midland Building Cleveland, Ohio 44115	IV-D-5
4. Mr. A.H. Nickolaus Texas Chemical Council 100 Brazos, Suite 200 Austin, TX 78701-2476	IV-D-6
5. Ms. Geraldine V. Cox Chemical Manufacturers' Association 2501 M. Street, North West Washington, DC 20037	IV-D-7
6. Mr. Robert N. Harrison Western Oil and Gas Association 727 West Seventh Street Los Angeles, CA 90017	IV-D-8; IV-D-8a; IV-D-1; IV-D-2
7. Mr. James A. Young Independent Refiners' Association 900 Wilshire Boulevard, Suite 1024 Los Angeles, CA 90017	IV-D-9
8. Mr. Phillip L. Youngblood Conoco, Inc. Suite 2136, Post Office Box 2197 Houston, TX 77252	IV-D-10
9. Mr. Roger Noble John Zink Company 4401 S. Peoria Tulsa, OK 74105	IV-D-11

TABLE 1-2. LIST OF COMMENTERS ON PROPOSED STANDARDS OF PERFORMANCE FOR FUGITIVE EMISSION SOURCES IN THE PETROLEUM REFINING INDUSTRY (Continued)

COMMENTER AND AFFILIATION	DOCKET ITEM NO.
10. Mr. Herman A. Fritschen Cities Service Company Post Office Box 300 Tulsa, OK 74102	IV-D-12
11. Mr. Alan J. Schuyler ARCO Alaska, Inc. Post Office Box 360 Anchorage, Alaska 99510	IV-D-13
12. Mr. Paul M. Kaplow Atlantic Richfield Company Post Office Box 2679-T.A. Los Angeles, CA 90051	IV-D-14
13. Mr. William F. O'Keefe American Petroleum Institute 201 L Street, Northwest Washington, DC 20037	IV-D-15
14. Mr. A.G. Smith Shell Oil Company One Shell Plaza Post Office Box 4320 Houston, TX 77210	IV-D-16
15. Mr. J.D. Reed Standard Oil Company (Indiana) 200 East Randolf Drive Chicago, IL 60601	IV-D-17
16. Mr. J.J. Moon Phillips Petroleum Company Bartlesville, OK 74004	IV-D-18
17. Mr. Louis R. Harris B S & B Safety Systems, Inc. 7455 East 46th Street Post Office Box 45590 Tulsa, OK 74145	IV-D-19
18. Mr. R.H. Murray Mobil Oil Corporation 3225 Gallows Road Fairfax, VA 22037	IV-D-21

TABLE 1-2 LIST OF COMMENTERS ON PROPOSED STANDARDS OF PERFORMANCE FOR FUGITIVE EMISSION SOURCES IN THE PETROLEUM REFINING INDUSTRY (Concluded)

COMMENTER AND AFFILIATION	DOCKET ITEM NO.
19. Mr. M.W. Anderson Kerr-McGee Corporation Kerr-McGee Center Oklahoma City, OK 73125	IV-D-22
20. Mr. J.H. Leonard Beacon Oil Company 525 West Third Street Hanford, CA 93230	IV-D-23
21. Mr. William L. Rogers Gulf Oil Corporation Post Office Drawer 2038 Pittsburgh, PA 15230	IV-D-24
22. Mr. Joseph M. Macrum Texaco U.S.A. Post Office Box 52332 Houston, TX 77052	IV-D-25 IV-D-25a
23. Mr. Bruce Blanchard U.S. Department of the Interior Washington, DC 20240	IV-D-26
24. Mr. David D. Doniger National Resources Defense Council, Inc. 1725 I Street, N.W. Washington, D.C. 20006	IV-D-30

2.0 STANDARDS

This chapter summarizes public comments and responses to comments pertaining to the proposed standards. Section 2.1 presents those comments and responses that pertain to the standards in general; Sections 2.2 through 2.8 present comments and responses that pertain to particular requirements for each piece of equipment covered by the standards; and Section 2.9 presents comments and responses on control devices. In Chapter 2 and the following chapters, information used in responding to the public comments is referenced according to document number within the project docket, Docket No. A-80-44.

2.1 GENERAL DISCUSSION

Comment:

Commenters (IV-D-5, IV-D-12, and IV-D-25) wrote that the standards should be the same as State requirements. Commenters (IV-D-22 and IV-D-24) argued that the proposed standards would be redundant and conflict with existing State regulations. For example, States may presently require leak detection and repair of compressor seals while the NSPS would require equipment specifications. One commenter (IV-D-12) thought the standards would require the abandonment of existing programs.

Response:

The Clean Air Act Amendments of 1977 require each State in which there are areas where the national ambient air quality standards (NAAQS) are exceeded to adopt and submit revised State implementation plans (SIP's) to EPA. Sections 172(a)(2) and (b)(3) of the Clean Air Act require that nonattainment area SIP's include reasonably available control technology (RACT) requirements for stationary sources. EPA issues Control Techniques Guidelines (CTG) documents to provide State and local air pollution control agencies with an initial information base for proceeding with their own assessment of RACT for specific stationary sources.

Most State regulations for fugitive VOC emissions are based on the "Control of Volatile Organic Compound Leaks for Petroleum Refinery Equipment," EPA-450/2-78-036, released by EPA in June 1978 (Document No. II-A-6). This CTG was issued by EPA to provide information and guidance to State and local air pollution control agencies for their use in regulating VOC emissions in oxidant nonattainment areas. The CTG identifies RACT that can be applied to existing refineries to control VOC from equipment leaks.

The Clean Air Act requires that standards of performance for stationary sources reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction (best demonstrated technology, BDT), taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impacts, and energy requirements. NSPS applies to newly contructed, modified, or reconstructed facilities in both attainment and non-attainment areas. Because the purpose of the NSPS and the purpose of the State regulations, as reflected in the Clean Air Act, differ EPA believes that it would be inappropriate for the requirements to be necessarily the same.

The standards are not redundant, and no substantial conflict occurs between the NSPS and State requirements. The NSPS requirements and the CTG recommendations are identified and compared in Table 2-1. The NSPS require monthly/quarterly leak detection and repair of gas and light liquid valves and monthly leak detection and repair for light liquid pumps, while the CTG recommends less frequent leak detection and repair (quarterly leak detection and repair for gas valves and yearly leak detection and repair for light liquid valves and pumps). The increased monitoring frequencies of the NSPS are reasonable because the incremental cost and emission reduction are reasonable.

The standards for pressure relief devices and compressors are based on the use of equipment, whereas the CTG recommends leak detection and repair for pressure relief devices and compressors. The CTG includes no recommendation for sampling connections. The standards require equipment and work practices for sampling connections; again, there is no conflict between the NSPS and State requirements. The standards

Table 2-1. COMPARISON OF CTG RECOMMENDATIONS AND NSPS REQUIREMENTS

Source	CTG		NSPS	
	Routine Inspection Interval	Equipment Specification/ Work Practice	Routine Inspection Interval	Equipment Specification/ Work Practice
Valves				
Gas/Vapor	Quarterly	None	Monthly[a]	None
Light Liquid	Annual	None	Monthly[a]	None
Open-ended Lines (purge, drain, sample lines)	None	Caps	None	Caps
Sampling Connections	None	None	None	Closed purge
Pump Seals				
Light Liquid	Annual[a]	None	Monthly[b]	None
Relief Devices	Quarterly	None	None	Rupture disks[c]
Compressor Seals	Quarterly	None	None	Closed vent to control device

[a] The standards require monthly monitoring of valves, except that quarterly monitoring would be allowed for valves which have been found not to leak for two successive months.

[b] For pumps, instrument monitoring would be supplemented with weekly visual inspections for liquid leakage. Pumps with evidence of liquid leakage are to be monitored and if emission concentrations are 10,000 ppm or more they must be repaired

[c] Standard is "no detectable emissions."

also provide alternatives for valves that allow an owner or operator to continue the CTG control level for process units with less than 2.0 percent of the valves leaking. Other alternatives are allowed for valves, and three alternatives are allowed for pumps. EPA does not believe that the standards would conflict with most existing State regulations. The standards apply only to affected facilities (compressors are one of the facilities covered by the standards) that commence construction or modification after January 4, 1983. A conflict may occur if State agencies require leak detection and repair. The conflict is requiring unneeded leak detection and repair for compressors equipped with the controls required by the standards. Most State air pollution control regulations include variance procedures that owners or operators can assess. In the few cases where it occurs, costs would not be unreasonable. These procedures could be used to eliminate the conflict. After considering the differences between the CTG and NSPS, EPA concluded that the NSPS requirements are not redundant and do not substantially conflict with existing State regulations.

EPA also judged that the standards do not require or motivate refiners to abandon existing plant leak detection and repair programs. In making these judgments, EPA noted that the CTG was based on RACT, whereas the NSPS is based on BDT, considering costs. In determining BDT, EPA analyzed the cost effectiveness and incremental cost effectiveness of a variety of control techniques (presented in Table 2-2), including those presently required by State regulations. EPA also included existing programs in assessing the impacts of the NSPS. Based on this, EPA determined that the costs of the control techniques selected as the basis for the standards are reasonable. The final standards and existing programs should work together, yet to the extent that some existing regulations may conflict with the NSPS, refiners can request a variance for existing programs as discussed in the previous paragraph.

Comment:

Some commenters (IV-D-5, IV-D-16, and IV-D-25) contended that EPA overstated the emission reductions of the proposed standards by understating baseline emissions. The emission reductions should reflect the sources covered by State regulations. Another commenter (IV-D-15)

Table 2-2. SUMMARY OF THE INDIVIDUAL COMPONENT CONTROL IMPACTS[a]

Fugitive Emission Source	Control Technique	Emission Reduction (Mg/yr)	Average Cost Effectiveness (\$/Mg)[b]	Incremental Cost Effectiveness (\$/Mg)[c]
Pressure relief devices	Quarterly LDR	4.4	(170)	(170)
	Monthly LDR	5.3	(110)	250
	Rupture disks[d]	9.8	410	1,000
Compressors	Controlled degassing vents	16.5	150	150
Open-ended valves	Caps on open ends	2.8	460	460
Sampling connection systems	Closed purge sampling	2.6	810	810
Valves	Quarterly LDR	66	(110)	(110)
	Monthly LDR	77	(60)	310
	Sealed bellows valves	110	4,700	16,700
Pumps	Annual LDR	3.0	860	860
	Quarterly LDR	9.8	157	(140)
	Monthly LDR	11.5	158	170
	Dual mechanical seal system	13.9	2,000	10,900

(xx) = Cost savings
LDR = Leak detection and repair

[a] Costs and emission reductions are based on fugitive emission component counts in Model B from the BID for the proposed standards, EPA-450/3-81-015a, page 6-3, and from Tables A-2 through A-13 of Appendix A.

[b] Average Cost Effectiveness = net annualized costs per component ÷ annual VOC emission reduction per component.

[c] Incremental Cost Effectiveness = (net annualized cost of the control technique - net annualized cost of the next less restrictive control technique) ÷ (annual emission reduction of control technique - annual emission reduction of the next less restrictive control technique).

[d] Underlined control techniques were selected as basis for standards.

wrote that it was not clear whether the baseline emissions represent existing levels of control or no control.

Response:

Promulgation of the Priority List (40 CFR 60.16, 44 FR 4922, August 21, 1979), reflects EPA's determination that refinery fugitive emissions are a major source category which contribute significantly to air pollution. As discussed in Chapter 7 of the BID for the proposed standards, baseline reflects a weighted average of refineries in attainment (no regulations) and nonattainment (recommendations of the refinery CTG) areas and, therefore, does account for sources covered by State regulations. Table 2-3, taken from the BID for the proposed standards, compares the projected VOC emissions under baseline level of control for 1982-1986 with projected emissions under both the uncontrolled level and the level of control obtained by the standards.

Comment:

One commenter (IV-D-6) stated that the proposed regulations are difficult to follow because of the exemptions, alternatives, and the Federal Register format, which requires almost continuous "cross-checking." The commenter suggested that the requirements for a specific component appear as a separate section to improve the readability of the regulations.

Response:

The format of the standards does require some cross-checking as the commenter mentions. However, the standards do present individual component requirements in separate sections as requested by the commenter and discuss common aspects of these individual component requirements in other sections (e.g., Section 60.595 Test Method and Procedures). This format greatly reduces the redundancy in presenting the regulations.

Comment:

One commenter (IV-D-14) maintained that the standards should apply only to valves because they are the largest single source, and annual inspection and repair programs are cost effective in reducing emissions only from valves. In addition, the commenter wrote that limiting the standards to valves would result in a more efficient and practicable approach to reducing emissions from new, modified, and reconstructed sources. Other fugitive emission components comprise a smaller source of emissions, and control for these components either has not been demonstrated or has not been shown to be cost effective.

Table 2-3. PROJECTED VOC FUGITIVE EMISSIONS FROM FACILITIES FOR 1982-1986 UNDER UNCONTROLLED, BASELINE, AND NSPS[a]

	Total Fugitive Emissions Projected (Gg/yr)		
Year	Uncontrolled[b]	Baseline[c]	NSPS[d]
1982	12	9.2	3.4
1983	24	19	7.1
1984	37	29	11
1985	51	39	14
1986	64	49	18

[a] The emissions estimates are taken from Table F-10 of the BID for the proposed standards. The estimates are based on projected new, modified, and reconstructed model units.

[b] The uncontrolled emissions projection assumes all refineries are operating in the absence of regulations (Regulatory Alternative I).

[c] The baseline emissions projection reflects normal existing operations in refineries nationwide in the absence of any new regulations. The baseline assumes that refineries in nonattainment areas for ozone are subject to regulations similar to those recommended in the refinery Control Techniques Guideline document (Document No. II-A-6), Regulatory Alternative II in the BID for the proposed standard. Baseline emissions are calculated as the weighted sum of the proportion of refineries in attainment and nonattainment areas for ozone: (0.56)(Regulatory Alternative II) + (0.44) (Regulatory Alternative I).

[d] Emissions projected under promulgated standards.

Response:

EPA agrees with the commenter that valves represent the largest source of fugitive VOC by component type in a refinery. However, the uncontrolled emission factors presented in the BID for the proposed standards, Table 3-1, clearly show that pressure relief devices, compressors, and light liquid service pumps also have relatively high emission rates. EPA has determined that fugitive emission sources in petroleum refinery equipment contribute significantly to ozone pollution and, therefore, were included in a source category on the NSPS Priority List in 40 CFR 60.16. Under Section 111(b)(1), EPA is now required to set standards of performance for all new sources within this listed category for which EPA can identify BDT (considering costs). EPA is selecting BDT (considering costs) based on cost-effective control techniques for the source. Several types of refinery equipment may emit VOC leaks, and, therefore, each is a subset of the entire source. In selecting BDT, EPA is setting standards for each fugitive emission component with demonstrated, cost-effective controls (see Table 2-2). Because EPA maintains that the standards provide cost-effective control for other sources as well as valves, equipment other than valves will be covered by the standards.

Comment:

Commenters (IV-D-12 and IV-D-25) indicated that the proposed standards are inflexible, manpower intensive, and not cost effective.

Response:

EPA has expended considerable effort to make these standards as definitive and flexible as possible. As discussed in the preamble for the proposed standards, different formats are required for different fugitive emission sources because the characteristics of the emission sources and the availability of the measurement method used for fugitive emission sources differ among the sources. Performance standards allow some flexibility because any control technique may be used if it achieves the required level of emission reduction. However, for most refinery equipment, it is not feasible to prescribe a performance standard. EPA has selected performance standards for certain equipment, where practicable, and has provided alternative standards when equipment, work practice, design or operational standards have been used. Hence, multiple control options are allowed wherever practicable and are considered equivalent to the control techniques selected as BDT. In contrast to the comment, EPA considers the manpower requirements of the standards worthwhile and a prudent use of resources as evidenced by the cost effectiveness of the control techniques presented in Table 2-2. The overall cost effectiveness of the standards is approximately $130/Mg, which EPA considers reasonable.

Comment:

A commenter (IV-D-15) expressed some confusion on the cost-effectiveness information presented in Table 1 of the preamble to the proposed standards. The values presented in Table 1, the commenter said, cannot be generated from the emissions, labor, and cost information presented in the BID. The commenter added that since the BID for the proposed standards does not contain a cost-effectiveness analysis for each component as given in Table 1 of the preamble to the proposed standard, a supplemental document should be prepared by EPA showing calculations and should be made available for public comment prior to promulgating the standards.

Response:

Upon reviewing the calculations that were performed to generate the cost-effectiveness information presented in Table 1 of the preamble to the proposed standards, it was determined that a mistake was made in the valve emission reduction calculations. This is explained in Section 2.2.1. In addition, the analysis for pumps was changed as discussed in the AID (Document No. II-A-41) and Section 2.3.1. The corrected valve and revised pump calculations are presented in Appendix A and the results are summarized in Table 2-2.

The commenter is correct in that individual cost-effectiveness estimates are not presented in the BID for the proposed standard; instead, the proposal BID presents cost-effectiveness estimates for regulatory alternatives. The proposal BID does, however, present the method for calculating the cost, emission reduction, and cost effectiveness for the various levels of control from which individual component impacts can be derived. In addition, a previous supplemental information document (Document No. IV-D-41) has been issued by EPA that explicitly presents the method for calculating individual component impact estimates.

EPA is also providing the derivation of individual component impacts in Appendix A.

EPA does not believe that a supplemental information document is warranted. In September 1980, EPA requested public comments on the preliminary model units and regulatory alternatives; in May 1981, the preliminary draft BID was distributed to the National Air Pollution Control Techniques Advisory Committee, industry, environmental groups, and other interested persons; and in April 1982, EPA announced the availability of and invited comments on an additional information document on the emissions, emission reductions, and costs for control of fugitive emission sources of organic compounds. Because the commenters did not question EPA's method of analysis and EPA's review of the comment did not change its analysis, an additional information document is not warranted.

2.2 VALVES

2.2.1 Basis for Standards

Comment:

One commenter (IV-D-15) wrote that it was not clear whether the cost-effectiveness values presented in Table 1 of the proposal preamble are based on a continuing monthly monitoring schedule or the reference leak detection and repair program for valves that allows less frequent monitoring of non-leakers.

Responses:

In selecting the basis of the standards for valves, EPA considered different alternative monitoring periods for valves: annual, quarterly, and monthly monitoring. In reviewing the public comments, EPA re-examined the incremental impacts of the three monitoring intervals (Document No. IV-B-10). Each of these intervals was compared in terms of the emission reduction achievable and cost-effectiveness of the leak detection and repair programs as presented in Appendix F of the BID for the proposed standards. Monthly monitoring was selected because it achieves the largest emission reduction, 77 Mg per year for a Model Unit B. EPA also judged that monthly monitoring has a reasonable cost effectiveness, a credit of $60/Mg, and that the incremental cost effectiveness of $310/Mg VOC for monthly versus quarterly monitoring is reasonable. Based on these estimates EPA considers monthly monitoring BDT for valves.

Available data (II-A-21 and II-A-26) indicate that leak recurrence is an important factor in predicting leaks from valves. That is, if a valve leaks, then it is more likely to leak in the future than a valve that has not leaked. These data also show that some valves leak less frequently than others. Because leak recurrence is important in predicting leaks, EPA considers that the annual cost of monthly monitoring of valves that leak infrequently would probably be unreasonably high in comparison to the annual cost of quarterly monitoring, considering the emission reduction achieved by monthly and quarterly monitoring. Therefore, the standards allow quarterly monitoring for valves which have been found not to leak for two successive months resulting in a hybrid monthly/quarterly monitoring program.

It is possible that basing the standards on monthly monitoring, but allowing monthly/quarterly monitoring, has led to confusion. The basis of the standards remain monthly so the cost-effectiveness estimates for valves given in the proposal preamble are based on continuing monthly monitoring. By basing the cost analysis on monthly monitoring rather than monthly/quarterly, a maximum cost impact estimate was evaluated. It is important to note, however, that the actual cost effectiveness of the standards for valves is likely to be even better because the standards allow quarterly monitoring for valves that have been found not to leak for two successive months (monthly/quarterly monitoring). EPA expects that most affected facilities would follow the monthly/quarterly reference leak detection and repair program and, further, that most valves would be on the quarterly inspection schedule. Hence, the actual costs for valves under the standards is likely to be more closely represented by the costs estimated for quarterly monitoring.

Upon reviewing the calculations that were performed to generate the information presented in Table 1 of the preamble to the proposed standards, it was determined (Document No. IV-B-3) that an error was made in the valve emission reduction calculations. This is likely what caused the commenter's confusion on the calculation of the impacts of the valve standards. Valve impacts are calculated based upon a Model

Unit B refinery unit component inventory (260 gas/vapor service valves and 500 light liquid service valves). The valve emission reductions were underestimated by mistakenly using a weighted average of the emission reductions for the two types of valves, gas/vapor and light liquid, rather than the total emissions from the two types of valves. The corrected emission reductions impacts are presented in Table 2-4. In rechecking the cost and emission reduction calculations, rounding resulted in a slight differences in the cost effectiveness and incremental cost effectiveness values. The revised emission reduction and cost effectiveness for monthly leak detection and repair are 77 Mg/year and a savings of $60/Mg VOC emission reduction, respectively. The incremental cost-effectiveness from quarterly to monthly monitoring now shown is $310/Mg of VOC emission reduction. The revised numbers have been incorporated into the analysis of the final standards and did not affect any of the decisions on the proposed standards.

Comment:

A number of commenters (IV-D-8, IV-D-12, IV-D-14, IV-D-16, IV-D-17, IV-D-18, IV-D-21, and IV-D-25) wrote that monthly monitoring of valves is not cost effective. Commenters contended that their experience with less frequent monitoring intervals (quarterly and annual monitoring) shows that these intervals are more reasonable. Some commenters recommended annual monitoring for valves because the results of programs performed at West Coast (California) refineries indicate that leak occurrence rates for valves under annual monitoring are lower than EPA's assumed estimate of 3.8 percent on a quarterly basis. Two commenters (IV-D-8 and IV-D-14) stated that their refinery-wide leak occurrence rate was only 1 to 2 percent on an annual basis. Similarly, another commenter (IV-D-21) stated that annual inspection programs result in leak occurrence frequencies as low as 0.3 percent.

One commenter (IV-D-15) recommended that EPA obtain leak detection and repair program data generated in California. Other commenters (IV-D-14, IV-D-25a, and IV-D-31) provided data on leak detection and repair programs. In particular, information was provided EPA concerning leak frequency, leak occurrence and recurrence rates, and monitoring and maintenance costs.

Table 2-4. REVISED EMISSION REDUCTIONS AND COST FOR VALVE LEAK DETECTION AND REPAIR PROGRAMS[a]

	Monitoring Interval	
	Quarterly	Monthly
Emission Reduction (Mg/yr)[b]		
Proposed[c]	31.7	37.1
Revised[a]	66	77
Average $/Mg[d]		
Proposed[c]	(90)	(40)
Revised[a]	(110)	(60)
Incremental $/Mg[e]		
Proposed[c]	---	300
Revised[a]	---	310

(xx) = Cost savings.

[a] Memorandum from T.W. Rhoads, PES, Inc., to Docket A-80-44. VOC Emission Reduction and Cost-Effectiveness Estimates. July 14, 1983. Document No. IV-B-3.

[b] Based on Model Unit B component counts, BID for proposed standards.

[c] From Table 1 preamble for proposed regulation.

[d] Average dollars per megagram (cost effectiveness) = net annualized cost per component ÷ annual VOC emission reduction per component.

[e] Incremental dollars per megagram = (net annualized cost of monthly monitoring - net annualized cost of quarterly monitoring) ÷ (annual emission reduction of monthly monitoring - annual emission reduction of quarterly monitoring).

Response:

As discussed in the previous response, EPA evaluated three monitoring intervals for valves: annual, quarterly, and monthly. Each of these intervals was compared in terms of the emission reduction achievable and the cost effectiveness of the leak detection and repair programs. Annual and quarterly monitoring are more cost effective than monthly monitoring, however, the standards require monthly monitoring because it provided the greatest emission reduction at a reasonable cost effectiveness and incremental cost effectiveness.

The commenters are questioning the cost effectiveness estimates used by EPA based mostly on their experiences with monitoring required by State implementation plans in California. However, the effectiveness of leak detection and repair programs in California is not strictly comparable with the regulatory alternative used in the BID for the proposed standards. The commenters refer to the South Coast Air Quality Management District (SCAQMD) Rule 466.1 on leakage from valves and flanges. Contrary to the commenter's contention, monitoring under Rule 466.1 is not strictly on an annual basis, but rather biannual for the first year and annual in the following years. Like the final standards, Rule 466.1 focuses on recurring leakers; Rule 466.1 requires follow-up inspections on leaking equipment at 3 months and, if they are still leaking at this inspection, follow-up inspections at successively shorter periods, and in addition, Rule 466.1 requires all repairs to be completed within 2 working days unless a variance is obtained. In contrast, the standards require that repairs be made as soon as practicable with an initial attempt within 5 days and completion within 15 days. The standards also provide for automatic delay of repairs to a process unit turnaround. Another important distinction is distance at which monitoring measurements are taken. The standards require measurement at the source, whereas the SCAQMD Rule 466.1 allows measurement at 1 cm from the surface. Thus, simple comparison of data from refineries subject to the SCAQMD rules to EPA's data base is misleading.

In response to these comments, EPA reviewed and compared equipment leak data from current industry leak detection and repair programs to the data used in developing the standards. The results of this analysis are presented in Appendix C. Where these data relate to specific comments on the standards, they are also incorporated into the response to the comment.

Section C.1.2 of Appendix C presents occurrence rate data obtained from industry leak detection and repair programs. An EPA study found (Document No. IV-B-11 and Section C.4) that the occurrence rates observed at two refineries in the South Coast Air Quality Management District (SCAQMD) are similar to the occurrence rates EPA used to estimate the national average for evaluating the effectiveness of leak detection and repair programs. Other existing leak detection and repair programs, however, have resulted in low annual occurrence rates as the commenters argued. However, the occurrence rate data obtained from refineries with existing leak detection and repair programs may be underestimated as a result of differences, as discussed above, in the requirements of existing regulations and those considered in developing the standards.

To the extent EPA data do not reflect certain process units covered by current plant practices (State regulation or otherwise), the standards have been developed to define BDT (considering costs) appropriately taking this into account. As discussed in the first response in this section and in the presentation before the National Air Pollution Control Techniques Advisory Committee (NAPCTAC) in June of 1981 (Document No. II-B-34) and in the preamble to the proposed standards, EPA believes that monthly monitoring for valves with a history of low leak rates is unnecessary. The final standards, therefore, allow monthly/quarterly monitoring, and alternative standards are provided for units with low rates. EPA believes the standards and the alternative standards represent BDT for all units covered by the standards.

Comment:

One commenter (IV-D-14) submitted the results of an LDAR Model run which calculated an incremental cost effectiveness from annual to monthly monitoring of $5,900/Mg. In addition, this commenter added that this LDAR Model run predicted emission reductions from the annual inspection program at a West Coast refinery would achieve a greater emission reduction than EPA's estimate for monthly monitoring, 72 percent versus 70 percent, respectively.

Response:

EPA reviewed (Document No. IV-B-16) the commenter's LDAR Model run and found several problems with the data inputs used by the commenter. The commenter used 1982 costs, rather than May 1980 costs that were used for the basis of the standards. Also, the commenter's use of occurrence rates in the analysis was incorrect. The commenter substituted different (2.0 percent annual) occurrence rates without also correcting the initial leak frequency and emission factors, which are a function of the occurrence rate. In lowering the occurrence rate, a corresponding reduction in the initial leak frequency and average emission factor should occur (Document Nos. II-B-43 and II-B-7). The commenter wrote that the 2.0 percent occurrence rate represents the West Coast annual inspection program, yet, as discussed in the previous response, direct comparison of annual monitoring under Rule 466.1 with the standards for valves is misleading. Also, the commenter did not use the LDAR Model input values that they indicated. The commenter's occurrence rates were purportedly 2.0 percent annual occurrence rates for annual and monthly monitoring, yet, in reviewing the commenter's analysis, it was found that an 8 percent annual occurrence rate was used to evaluate monthly monitoring. In addition, the commenter failed to use half the inputs the commenter said would provide a better estimate of the impacts of leak detection and repair programs. Correcting just the occurrence rate (to 2.0 percent annual occurrence for both annual and monthly monitoring) and the cost basis (to 1980 dollars) in the commenter's data inputs results in an 80 percent emission reduction for monthly monitoring (significantly more than the 72 percent reduction achieved by annual monitoring in the comment) and a cost effectiveness of monthly monitoring of $500/Mg and an incremental cost effectiveness between annual and monthly monitoring of $1,900/Mg. EPA and the reported source of the commenter's estimates do not believe the inputs the commenter used are representative.

Comment:

Two commenters submitted that monthly monitoring would be more costly than EPA estimated. One commenter (IV-D-24) wrote that the costs for monthly monitoring at one refinery would increase from $6.40 per component per year for quarterly monitoring to approximately $19 per component per year for monthly monitoring. Another commenter (IV-D-25) and IV-D-25a wrote that the cost per component given in the April 1981 preliminary draft BID, $0.82, is far below the $2.57 per component monitoring cost experienced at his refinery in 1982. The commenter further stated that they had a total program cost of $4.82 per component.

Response:

EPA calculated the costs per valve based on the data and information discussed in "Fugitive Emission Sources of Organic Compounds - Additional Information on Emissions, Emission Reductions, and Costs" (AID), April 1982, EPA-450/3-82-010. EPA requested public comments on the monitoring labor requirement and cost estimates in the AID. EPA has previously received specific comments at the June 1981 meeting of the National Air Pollution Control Techniques Advisory Committee (NAPCTAC) on the information in the BID for the proposed standards. After reviewing the NAPCTAC comments and comments on the AID, EPA added some provisions making them more practicable where possible, however, the standards remain essentially the same.

To compare the first commenter's cost estimates to the EPA's estimates, it was necessary to contact the commenter to determine the basis of his costs. From the additional information obtained (IV-F-28), EPA learned that the leak detection and repair costs submitted were mostly for valves (about 90 percent), but included some components other than valves. Thus, the commenter was comparing the costs for leak detection and repair for all components to the EPA's cost estimates for valves. Since the cost to monitor and repair components other than valves are typically higher than that for valves, the commenter's costs overestimate the actual cost per valve he incurred. EPA also learned that the costs provided reflect a contractor's total labor costs for monitoring and repairs from a refinery inspection in 1982 dollars. The costs submitted did not include the refiner's overhead.

The first commenter's costs were adjusted for 1980 dollars (to be consistent with the EPA's cost estimates) by using cost indexes from Chemical Engineering (Document Nos. II-I-58 and IV-J-2). An overhead rate was also applied to the commenter's costs consistent with EPA's estimates. The results, compared in Table 2-5, show that EPA's cost for quarterly monitoring is somewhat higher, $5.91 per valve compared to $4.22 per valve. The commenters adjusted estimate for monthly monitoring, however, is somewhat higher than EPA's, $17.5 per valve compared to $16.00 per valve. The comparison of the commenters' costs and EPA's estimates indicates that the EPA's estimates are reasonably close to the plant's expenditures for leak detection and repair. This commenter did not comment on the basis for the EPA cost estimates. Also, to the extent that an individual plant's costs may be higher than the EPA estimates, the EPA costs appropriately reflect the nationwide average costs to comply with the standards, such that any individual plant costs may be somewhat higher or lower.

Table 2-5. COMPARISON OF COMMENTER AND EPA ANNUAL COSTS FOR LEAK DETECTION AND REPAIR

	Commenter Estimates For Components[a]			EPA Estimates For Valves[b]
Monitoring Period	1982 Dollars	1980 Dollars	1980 Dollars plus Overhead	1980 Dollars
Quarterly	6.40	4.22	5.90	9.20
Monthly	19.00	12.50	17.50	16.00

[a] From Document Nos. IV-D-24 and IV-E-28. Cost are adjusted to 1980 dollars using cost indexes (Document Nos. II-I-58 and IV-J-2). Costs presented in the comment letter are based on 1982 dollars. Overhead is estimated as 0.40 x monitoring and repair labor cost.

[b] From Document No. IV-B-10.

The second commenter's costs are based on first year costs to implement a leak detection and repair program similar to Regulatory Alternative II in the BID for the proposed standards, which specifies, quarterly inspections of gas service components and annual inspections of liquid service components. A review of the commenter's cost data (see Section C.1.5 of Appendix C) found the commenter's actual costs to be similar to EPA's cost estimates when compared on a common basis (e.g., adjusting to a 1980 cost basis, overhead rate). The commenter's total leak detection and repair costs in 1980 dollars, about $71,100 per year, compare to an EPA estimate of about $60,900 per year for a similar scenario. Here again, the comparison is not strictly valid because the two estimates are based on different component populations. The commenter's data include an unknown number of component types not included in the CTG recommendations such as valve flanges and capped open ended lines.

The information EPA received from the commenters did not lead EPA to change the cost estimation methods. Therefore, EPA has not changed the basis for the costs and considers the costs of a monthly leak detection and repair program for valves to be reasonable (i.e., an average cost effectiveness (credit) of $60/Mg and an incremental cost of $310/Mg compared to quarterly monitoring.

2.2.2 Alternative Standards

Comment:

Some commenters (IV-D-5, IV-D-10, IV-D-24, and IV-D-30) wrote that they support the alternative standards for valves as they provide incentive for a facility to maintain a low incidence of leaking sources. One of the commenters (IV-D-10) wrote that the addition of alternative standards for valves was an improvement from the proposed standards for valves in the synthetic organic chemical manufacturing industry (SOCMI). Another commenter (IV-D-30), however, questioned the basis for allowing a 2.0 percent leaking valve rate when the objective is to keep the real leak rate below an average of 1.0 percent because most facilities would operate with a real leaking valve rate well above 1.0 percent.

Response:

EPA believes that monthly monitoring does not have a reasonable cost effectiveness for process units with a low percentage of valves leaking. EPA judged at proposal that for units with less than (on the average) 1.0 percent valves leaking, monthly monitoring is unreasonable. EPA has, therefore, included alternative standards for valves in units with a low percentage of leakers: (1) two skip period monitoring programs and (2) an allowable percentage of valves leaking (performance limit). This approach addresses the comment that, if annual leak detection and repair or some other reduction program reduces leak rates to an average of well under EPA's estimates, the cost effectiveness of monthly monitoring is unreasonable.

The alternative standards apply on an affected facility basis, (i.e., individual process unit). As was explained at proposal, the allowable percent (2.0 percent) of valves leaking was selected (Document No. II-B-43) after considering the costs and emission reductions of monthly monitoring of low leak units and the variability inherent in leak detection of valves. The variability in the number of valves which are found leaking at any one time (e.g., variability in the monitoring instrument, instrument operators, the piece of equipment, leak occurrence, and recurrence) in leak detection of valves can be characterized as a binominal distribution around the average percent of valves leaking. Inclusion of the variability in leak detection of valves is accomplished by straightforward statistical techniques based on the binominal distribution. An allowable percent of valves leaking of 2.0 percent, to be achieved at any point in time, would provide an owner or operator a risk of about 5 percent that greater than 2.0 percent of valves would be determined leaking when the average of 1.0 percent was actually being achieved. Based on these considerations, EPA considers an allowable percent of valves leaking of 2.0 percent to represent about one percent of valves leaking.

The first alternative specifies two statistically based skip-period leak detection and repair programs. Under skip-period monitoring programs, an owner or operator can skip from routine monitoring to less frequent monitoring after completing a number of consecutive monitoring intervals with performance levels less than 2.0 percent of valves leaking. The first skip-period program provides that after 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner may begin to skip one of the quarterly leak detection periods (semiannual monitoring). The second skip-period program provides that after 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods (annual monitoring). This skip period alternative standard also requires that, if an affected facility exceeds the 2.0 percent limit of valves leaking during the semiannual or annual inspection, the owner or operator must revert to the monthly/quarterly leak detection and repair program that is specified in the standards. The original criteria for skip monitoring would again have to be met before owners and operators can again skip monitoring periods.

The second alternative standard for valves is a performance standard that specifies a 2.0 percent limitation as the maximum percent of valves leaking within a process unit. This alternative standard would require a minimum of one performance test per year. This alternative provides an incentive for maintaining a low percentage of leaking valves level by implementing any type of leak detection and repair program or engineering controls at the discretion of the owner or operator.

Comment:

Several (IV-D-8, IV-D-12, IV-D-14, IV-D-16, IV-D-17, IV-D-18, and IV-D-21.) commenters suggested that the regulations should begin with annual inspections and require more frequent inspections only if needed. Another commenter (IV-D-25) wrote that industry would be reluctant to use the alternative standards due to noncompliance penalties.

Response:

Based on evaluation of data that EPA considers representative of petroleum refineries, EPA selected standards for valves that require monthly/quarterly monitoring. The standards, however, also provide alternatives for facilities (process units) with relatively low leak frequencies. The commenters are asking that the standards be structured to allow increasing the frequency of monitoring in high-leak units rather than decreasing the monitoring in low-leak units (as currently structured).

The standards for valves (monthly/quarterly monitoring) and the alternative standards are structured to assure that best demonstrated technology for valves is achieved initially and throughout implementation of the standards. The data (II-A-19) indicate that about 10 percent of the valves in a facility would be found leaking on an initial inspection. Hence, the standards are structured to identify and control leaking valves through relatively frequent monitoring initially, and once recurring leakers are identified and controlled, allow less frequent monitoring. If the standards were structured as the commenters propose (based on increasing monitoring frequency), less emission reduction would result by allowing longer time intervals before recurring leakers are controlled.

EPA agrees with the commenters in that owners and operators might be reluctant to use the alternative standard for allowable percentage of valves leaking. Use of this alternative standard would subject an affected facility to non-compliance penalties. The owner or operator of a process unit selecting the allowable percentage of valves leaking alternative would have to do performance tests initially, annually, and at other times requested by the EPA Administrator. If more than two percent of the valves are found leaking, the facility would not be in compliance with the regulation.

For many facilities it may be impossible to guarantee that the facility will always have less than 2.0 percent valves leaking. These facilities should consider implementing the skip-period monitoring programs outlined in the previous response. For facilities following the skip-period monitoring alternative standard, the "penalty" for having greater than 2.0 percent valves leaking is more frequent monitoring rather than non-compliance with the standard.

2.2.3 Special Provisions

The following comments and responses pertain to specific groups of valves and provisions in the standards for valves relating to them.

2.2.3.1 Difficult-to-monitor valves

Comment:

Two commenters (IV-D-12 and IV-D-15) maintained that difficult-to-monitor valves can not be eliminated in new units, even though they can be reduced in number. Therefore, the difficult-to-monitor provisions should be allowed for new facilities as well as existing facilities. Conversely, another commenter (IV-D-30) objected "to the exception from the monitoring requirements for supposedly difficult-to-monitor valves," claiming that, "it simply is not a significant burden for the monitoring personnel to use a ladder to reach valves higher than 2 meters off the ground." One commenter (IV-D-4) remarked that requiring monitoring personnel to carry equipment and climb a ladder to inspect difficult-to-monitor valves could double the cost of the monitoring program.

Furthermore, commenters (IV-D-8, IV-D-15, IV-D-21, and IV-D-25) maintained building new units without difficult-to-monitor valves will substantially increase unit costs because of extra ladders and platforms. The commenters added that it is too costly to monitor difficult-to-monitor valves. Another commenter (IV-D-24) requested that the EPA include a statement that would require annual monitoring "if practicable."

Response:

The intent of the standards is to monitor those valves that can be reached with the use of portable ladders or with existing supports such as platforms and fixed ladders. EPA defines valves that cannot be reached without extraordinary means, difficult-to-monitor valves, as those valves that cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface. EPA does not consider valves that can be reached from a portable ladder to be difficult-to-monitor, and hence the standards require operators to use portable ladders to monitor such valves.

EPA has estimated the cost for monitoring difficult-to-monitor valves in existing units (Document No. II-B-46) and determined that the cost effectiveness of monthly monitoring of difficult-to-monitor valves may be unreasonable, and that the average cost effectiveness for annual monitoring is reasonable. Hence, EPA proposed annual monitoring of difficult-to-monitor valves in existing facilities. The provision was not allowed for newly constructed affected facilities because commenters on the proposed standards for VOC fugitive emission in the synthetic organic chemicals manufacturing industry (Document No. IV-A-5, Section 4.2.4) wrote that difficult-to-monitor valves can be eliminated in new units. A refinery design engineer (IV-E-15) also indicated that new units can be designed with no difficult-to-monitor valves.

Upon reviewing the comments received on the proposed standards, EPA agrees with the commenters in that eliminating all difficult-to-monitor valves in new units may substantially increase the costs of constructing a new unit, for example, due to the necessity for additional fixed ladders and platforms. Yet, estimation of these additional costs is not possible due to the wide variability of factors such as the height of the valves and the ability to co-locate difficult-to-monitor valves (Document No. IV-B-13).

A refinery maintenance study (Document No. IV-A-3) found that about 3 percent of over 8,000 total valves investigated could not be reached without extraordinary aids such as scaffolding or cherry pickers. Based on these data and contacts with petroleum refinery design engineers (Document No. IV-B-13) the final standards allow the owner or operator of a newly constructed process unit to designate no more than 3 percent of its valves as difficult-to-monitor. The standards require annual monitoring of those valves. Limiting the percent of allowable valves that may be difficult-to-monitor provides the incentive to minimize the number of such valves in new units, while ensuring that an owner or operator would not incur unreasonable costs by attempting to eliminate all difficult-to-monitor valves in new units.

Comment:

Other commenters (IV-D-8, IV-D-21, and IV-D-24) wrote that it is unreasonable to stand on any elevated object and reach overhead to monitor for leaks because the practice is unsafe.

Response:

EPA does not believe that it is necessary to include a provision for valves that require operators to "reach overhead." The standards require operators to monitor valves and to repair leakers that can be reached safely with or without the aid of a ladder. The practice of reaching overhead to perform monitoring is not generally unsafe, and, to the extent this can be unsafe, personnel should be provided proper equipment (e.g., head and eye protection, ladders) and training as required by the Occupational Safety and Health Administration and refinery safety guidelines.

2.2.3.2 Unsafe-to-Monitor Valves

Comment:

Four commenters (IV-D-8, IV-D-15, IV-D-21, and IV-D-25) wrote that unsafe valves should never be monitored because they are no less safe to monitor annually than monthly. These valves are only safe-to-monitor when they are out of service, and it makes little sense to monitor components not in service. One commenter (IV-D-24) wrote that the proposed exemption of valves in unsafe locations, §60.5927(g)(2), should have a qualifying statement added so that it reads "required monitoring of the valve as frequent as practicable during safe-to-monitor times but not more than quarterly."

Response:

EPA agrees with the commenters that valves should never be monitored during unsafe-to-monitor conditions, that is, during periods of extreme temperature, pressure, or explosive process conditions that make these areas off-limits to all personnel. Accordingly, the standards do not require monitoring during unsafe periods. Valves that are considered unsafe-to-monitor are not unsafe-to-monitor all the time. Monitoring can conform to the requirements of the standards as much as possible, but monitoring does not need to occur during unsafe conditions. Valves that are routinely operated under safe conditions would be subject to the routine monthly monitoring required by the standards. Valves that are only safe-to-monitor once per quarter or year would be subject to quarterly or annual monitoring, respectively. The standards require an owner or operator to explain why a valve is unsafe-to-monitor and to develop a plan to monitor the valve when it is safe, as often as possible but not more than monthly. For valves that are safe-to-monitor only when they are out of service (for example, during a process unit shutdown), pressure testing such as is specified by API Standard 598 for new valves could be part of an owner's or operator's monitoring plan.

The provisions for unsafe-to-monitor valves were included in the proposed standards of performance for equipment leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry (46 FR 1136, January 5, 1981) because a few valves may be unsafe-to-monitor; the same provisions were proposed in these refinery standards. EPA believes that very few such valves exist in refineries.

Comment:

Another commenter (IV-D-16) requested that EPA delete the requirement to demonstrate that valves are unsafe-to-monitor and the need for a written plan for monitoring unsafe valves.

Response:

EPA is providing the exception for unsafe-to-monitor valves and does not believe other valves should be allowed to use this exception. Very few, if any, valves in a refinery would be considered unsafe-to-monitor by EPA. Thus, a demonstration that particular valves are unsafe-to-monitor and a written plan for monitoring these valves is not a significant burden upon owners or operators. These demonstrations and plans are needed to ensure compliance with the intent of the standards, which is use of best demonstrated technology, considering costs, on all new sources.

2.2.3.3 Small Valves

Comment:

One commenter (IV-D-22) stated that small valves, in general, have lower mass emissions at 10,000 ppm than larger valves and suggested that EPA provide a small valve exemption such as that in the State of Texas. In a refinery as many as 50 percent of all valves are 2 inches and smaller, and eliminating the monitoring requirement for these valves would lessen the monitoring burden. Another commenter (IV-D-15) wrote that a large number of the refinery valves are small valves servicing instruments or control system bypasses and that the repair of these small valves cannot be performed while in service. Hence, it was recommended that the standards apply only to valves 3/4 inch size or larger since repair costs for small valves is greater than for large valves.

Response:

The first commenter's request for a small valve exemption is predicated on his contention that small valves have lower emissions at 10,000 ppm than large valves. EPA contends, however, that the relationship between valve size and mass emissions at 10,000 ppm is not relevant, although the relationship for the average emissions per valve at or greater than 10,000 ppm is relevant in assessing the need for a small valve exemption. Nevertheless, the commenter's contention that valve size relates to valve emissions is not supported in any test data. On the contrary, EPA test data indicate that valve emissions are essentially independent of valve size. An EPA study (Document No. II-A-19) found only a slighly positive correlation between mass emissions from valves and valve line size (correlation coefficients (r) equal to or less than 0.150). Also, data from facilities with existing leak detection and repair programs, presented in Section C.1.3 of Appendix C, further demonstrate that small valves account for a significant portion of leaking valves. This data indicates that small valves (less than or equal to

3.8 cm or 1.5 inches) represent nearly half the valves found leaking. The commenter noted that the Texas State Implementation Plan exempts all valves that are 2 inches or smaller; however, he failed to add that the exemption is contingent upon demonstration that emissions would not increase by more than 5 percent as a result.

EPA agrees that some small valves may need to be replaced for repair, but the cost of repair for these valves is reasonable. EPA has estimated valve repair to require 1.13 labor hours based on 75 percent of all valves being repaired on-line and in service with a repair time of 10 minutes, and 25 percent of the valves requiring off line repair requiring 4 hours per repair (BID for the proposed standards, Chapter 8). EPA anticipates that most instrument valves are not in VOC service and would therefore not be covered by the standards. However, if they are in VOC service, small valves servicing instruments and control systems are normally field repairable. Most repairs would consist simply of replacing the stem packing ring. For valves in corrosive service, the stem may be deteriorated to the extent that an entire stem assembly (stem, packing, and stem tip seal) must be replaced. Repair time in either case would be less than 30 minutes (Document No. IV-B-8). Hence, small valves are no more expensive to repair than large valves. The data presented and discussed in Section C.1.3 also indicate that small valves are as repairable on-line as large valves. For those valves in critical service (i.e., those that cannot be isolated from the process), the standards provide for delay of repair until a process unit shutdown.

2.2.4 Monitoring Time

Comment.

A number of commenters (IV-D-4, IV-D-15, IV-D-18) were concerned with the EPA estimates of monitoring time. Two commenters (IV-D-4 and IV-D-15) stated that monitoring would require 2 minutes per valve. Another commenter (IV-D-18) reported that their experience found that a two-man team averages one valve every 3 minutes, so that 160 valves could be monitored in one 8-hour day. This commenter also noted problems with hiring part-time or full-time employees to conduct monitoring for the alternative standards; with training personnel; and with purchasing additional monitoring instruments.

Response:

The EPA monitoring time estimate of 1 minute per valve was taken initially from information provided by Exxon Company, U.S.A. (Docket No. II-D-22) based on an "in-depth study to determine the monitoring manpower requirements." The average monitoring time for a leak detection survey for valves was found to be 1 minute per valve for a two-man team (2 man-minutes). In another study conducted by Union Carbide Corporation (Document No. II-I-57) an estimated 400 to 500 sources (valves and other equipment) were screened per day. Although this estimate was based on a three-man team, the third person was a unit operator who provided process data. For a two-man monitoring team, this corresponds to 1.9 to 2.4 man-minutes per source (0.95 to 1.2 man-minutes per source per monitoring person). Information from other studies, including EPA studies, shows that monitoring times are generally less than 2 man-minutes. Phillips Petroleum Company conducted a study (Document No. IV-B-10) of a petroleum refinery and petrochemical complex in which 70,000 components were screened in about 936 manhours with a two-man team. This represents an average of 0.8 man-minutes per component. EPA also reviewed the results of recent California Air Resources Board (CARB) inspections of refineries in the South Coast Air Quality Management District (SCAQMD) and the Bay Area Air Quality Mangement District (BAAQMD). The data (presented in Section C.1.6 of Appendix C), submitted in part by one commenter (IV-D-31) and in part obtained from BAAQMD and SCAQMD (Document No. II-B-18) revealed that monitoring time averaged about 1 minute per valve for the more than 6,400 valves monitored in 12 refineries. In this effort, 2 monitoring instruments were used and more information than required under the standard was recorded, such as line size, time of monitoring, and valve type and function. Considering these data, the time estimate of 1 man-minute per valve (2 man-minutes per valve for a two-person team) used for costing purposes is reasonable.

In further reviewing the commenters's claim that EPA underestimated the time required to monitor a valve, EPA examined the effect on the cost effectiveness of monthly monitoring for valves assuming that twice the monitoring time (2 minutes per source) is needed (Document No.

IV-B-4). The results obtained from the LDAR Model show that monthly monitoring would have a cost effectiveness of $42/Mg and an incremental cost effectiveness from quarterly monitoring of $768/Mg. Hence, monthly monitoring would, nevertheless, be reasonable even if 4 man-minutes per valve were required.

The cost impacts presented in the background information document for the proposed standards (Chapter 8) included the cost for two monitoring instruments per model unit plus $3,000 per year (1980 dollars) for instrument calibration and maintenance. Therefore, the cost of additional monitoring instruments is accounted for in the cost impacts. Furthermore, the actual monitoring instrument costs incurred by a refinery may be less since monitoring instruments may be used for more than one process unit. The cost impacts are based on 2 monitoring instruments per process unit (affected facility). However, when there are several affected facilities in a refinery, it is likely that the refiner will not purchase two monitoring units for each of them.

Training plant personnel to use the monitoring instruments and perform equipment monitoring is also considered in the cost analysis. These costs are included as "Administrative and Support" costs (40 percent of the total monitoring labor and maintenance labor costs). Owners/operators may, however, choose to employ consultants to perform equipment monitoring. Use of consulting firms would eliminate the need to hire part-time or full-time employees for a short period of time (e.g., half a year), for example, if monitoring requirements are reduced through use of the alternative standards for valves.

It is noteworthy to reiterate that promulgation of Method 21 (48 FR 37598) provides an alternative monitoring technique, soap screening. Soap screening, although restricted to those valves with moderate surface temperatures, may significantly lower the average monitoring time. By soap screening valves, owners/operators will experience lower costs for monitoring instrument maintenance. Further, the standards provide for quarterly monitoring of valves which are found not leaking for two consecutive inspections. Hence, monthly/quarterly monitoring will lower costs as a result of reduced monitoring labor requirements and instrument wear.

Comment:

Some commenters (IV-D-17, IV-D-18 and IV-D-25) contended that the monthly monitoring requirements will not permit sufficient time for all of the components in a unit to be monitored and repaired. One commenter (IV-D-18) noted that it would be impossible for one two-man crew to complete all inspection work, process work orders, and complete recordkeeping requirements within the one-month time frame.

Another commenter (IV-D-25) offered the example of a facility having about 14,000 components to be monitored. Based on a crew monitoring 200 components per day, it would take 24 days for three crews to check the components (not including the time for repairs and rechecks).

Response:

The basis for the EPA time estimate for performing leak detection and repair is found in Table 8-3 of the BID for the proposed standards. An average (for valves, pumps, and pressure relief devices) monitoring time requirement per component can be estimated based upon the component distribution for Model Plant B, as shown in Table 2-6. The resulting average component monitoring requirement is about 2.3 man-minutes. Based on this estimate, a two-man monitoring team can inspect about 420 components in an 8-hour day. Hence, a single two-man monitoring team can inspect a Model Unit A in about 1 day, Model Unit B in 2 days, and Model Unit C in 5 days. Actual industry and EPA testing (Document No. II-A-41) has demonstrated that a two-man monitoring team can inspect between 400 and 500 components per day.

Table 2-6. Derivation of Average Component Monitoring Time

Component type	Number of components	Time to monitor (min.)	Persons	Total time (man-min.)
Valves	760	1	2	1520
Pumps	14	5	2	140
Relief valves	7	8	2	112
Total	781			1772

Average = 2.3 man-minutes per component.

EPA believes that a month provides more than enough time to complete leak detection and repair of an affected facility. As previously pointed out, even a large process unit, Model Unit C, can be monitored within a week by a single monitoring team, allowing three weeks to complete repairs, rechecks, process work orders, and recordkeeping within the one-month period. There are several other factors that also indicate that a month permits sufficient time to comply with the leak detection and repair requirements: (1) repairs are commenced concurrent with the onset of monitoring as specified in the repair requirements; (2) more than one monitoring team may be employed to perform the inspections; and (3) the use of soap screening may reduce the monitoring time required. In addition, since the standards for valves allow quarterly monitoring of valves not found leaking for 2 consecutive monthly inspections, most valves are likely to be monitored on a quarterly basis.

EPA recognizes that it is possible for individual facilities to expend less time monitoring than the EPA estimate of two man-minutes per valve, as discussed above, and possible to expend more time monitoring as the commenters imply. Nevertheless, EPA maintains that the basis for estimating labor hour requirements as presented in the BID for the proposed standards appropriately reflect the monitoring requirements for the petroleum refining industry. Hence, EPA believes that sufficient time is allowed in the period of one month to complete the leak detection and repair requirements.

2.2.5 Repair

Comment:

Several commenters wrote that the 5 and 15 day repair intervals should be extended. Some (IV-D-8 and IV-D-15) argued that an initial attempt at repair within 5 days should be extended because of holidays and weekends. Others (IV-D-5, IV-D-12, IV-D-16, IV-D-17, and IV-D-24) thought that the 5-day requirement was unnecessary provided repair was accomplished within 15 days. Another commenter (IV-D-18) requested that the repair intervals be extended to 15 days for initial repair and 30 days for final repair.

Conversely, another commenter (IV-D-30) contended that the first attempt at repair for valves and pumps should be made within 24 hours instead of 5 days. The commenter wrote that repair personnel should either accompany or trail the monitoring personnel and, therefore, the minor repairs (e.g., tightening a valve bonnet) could be completed (and rechecked) immediately.

Response:

The standards require that a first attempt at repairing a leaking valve or pump should be accomplished as soon as practicable but no later than 5 days after detection of a leak. Attempting to repair the leak within 5 days will help maintenance personnel identify the leaks which can be repaired without shutdown of the process unit. Valves or pumps that continue to leak after simple field repair attempts must be repaired within 15 days following initial leak detection. This interval provides time for properly isolating leaking valves that require more than simple field repair. The 15 days provides sufficient time to schedule and effect on-line repairs that a shorter period might not allow. Provisions have been made for delaying repair of those valves which are in critical service and cannot be bypassed. The two repair period requirements provide efficient reduction of emissions and allow sufficient time for flexibility in scheduling repairs of leaking equipment. A single period would simply permit delays in repairs that could otherwise be accomplished quickly.

Most valve repairs can be done quickly. This is evident from compliance experience of refineries with the South Coast Air Quality Management District Rule (Rule 466.1) for valves which requires repair within 2 working days. A 5-day period for initial attempts provides sufficient time to schedule field repair. Originally, EPA was considering a 3-day limit, but decided to increase the limit to 5 days to allow for holidays and weekends.

Requiring an initial attempt at repair within a shorter time period (e.g., 24 hours as suggested by one commenter) may, however, pose a significant problem to owners. With shorter repair periods, a repair crew would have to accompany or closely follow a monitoring crew, repairing leakers as they are detected in order to perform all initial attempts at repair within the required time interval. Although this is a repair technique often employed, some repairs cannot be performed as described in the comment. For example, a pump seal that is leaking may not be repairable while the pump is in operation due to casings which must be removed or safety hazards due to the shaft motion. In other instances, parts (such as a valve bonnet pressure plate) may be cracked and require replacement, making "on-the-spot" repair attempts impossible. In addition, shorter time periods may increase the cost of leak detection and repair. Because very few valves leak (about 10 percent initially and about 2 percent leaking per month in subsequent inspections), repair crews may spend much of the time on an inspection with few repairs to perform if they were to accompany the monitoring personnel. The logistics of coordinating monitoring and repair is further complicated when considering union regulations that may apply and that certain repairs require specially trained personnel to perform (e.g., control valves). EPA considers 5 days to be a reasonable time constraint for first repair attempts on leaking valves or pumps.

Comment:

One commenter (IV-D-30) indicated that EPA chose the 10,000 ppm leak definition because undirected repair attempts for leaks less than 10,000 ppm would lead to an increase in emissions. The commenter claimed that lowering the 10,000 ppm leak definition and requiring a directed repair program would not significantly increase the cost impacts of the standards and would produce a substantial reduction in emissions.

Response:

The "leak definition" is the instrument reading observed during monitoring that defines which sources require repair. The best leak definition would be the one that achieved the most emission reduction at reasonable costs. At a leak definition of 10,000 ppm, approximately 90 percent of the mass emissions from valves would be detected. EPA has determined (Document Nos. II-A-21, II-A-26 and II-A-42) that valves found leaking at levels of 10,000 ppm or greater can be brought to levels below 10,000 ppm with proper maintenance. A leak definition lower than 10,000 ppm may be practicable in a sense that leaks can be repaired to levels less than 10,000 ppm. However, EPA is unable to conclude that a leak definition lower than 10,000 ppm would provide additional emission reductions and, therefore, would be reasonable.

The commenter suggested that EPA require directed repair, whereby the tightening of packing is monitored simultaneously and continued until no further reduction of leak is observed from the valve. However, there is no evidence to support the commenters contention that directed maintenance will provide greater emission reductions than the requirements of the standards. The standards require owners/operators to continue to attempt repair if the initial attempt to repair a leaker fails to reduce emissions below 10,000 ppm. The standards require monitoring of a valve following attempted repair to determine if the repair attempt was successful. EPA also believes that requiring directed repair could be too costly. Directed repair may unreasonably complicate coordination of monitoring and repair personnel, especially in refineries where repair personnel are governed by union regulations.

Upon reviewing the comments, EPA has maintained the 10,000 ppm leak definition because it would address approximately 90 percent of the VOC emissions from valves at reasonable costs and reasonable cost effectiveness. Also, the final standards for valve repair remain unchanged from proposal in requiring the best practices, including monitoring following repair, because directed repair has not been demonstrated to be more effective in emission reduction and may have higher costs.

Comment:

One commenter (IV-D-30) was concerned that plant owners or operators may abuse the delay of repair provision that can be used when stocks of spare valves have been depleted. The commenter stated that this provision invites operators to maintain very small inventories of spare parts. A better approach suggested by the commenter is to require the operators to maintain sufficient stocks, and the inventory required should be readily determinable after monitoring several times.

Response:

The commenter appears to misinterpret the intent of the delay of repair provision. The standards require that owners or operators must show that valve assembly supplies had been sufficiently stocked before the supplies were depleted. This includes custom-order and unique parts, as well, to avoid delays of repair due to unavailability of parts. Despite what the commenter says, the provision does not invite operators to maintain small inventories of spare parts. Plant experience with delays will be considered if delay was reasonable.

2.3 PUMPS

2.3.1 Basis for Standards

Comment:

One commenter (IV-D-4) recommended that the EPA decrease the monitoring frequency for pumps based on the lower percentage of pumps found leaking during a recent refinery inspection. The commenter also suggested a skip-period alternative for pumps.

Response:

The basis of the standards for pumps is monthly leak detection and repair. One month provides the most effective leak detection and repair program for pumps, reducing emissions from a Model Unit B by 11.5 Mg per year, without imposing difficulties or unreasonable costs in implementing the program. EPA has determined (Document No. IV-B-2) that monthly monitoring has reasonable cost effectiveness, $158/Mg, and incremental cost effectiveness, $170/Mg between quarterly and monthly monitoring.

EPA data collected during screening studies on pump seals represent plants with and without existing control programs. EPA data represent pumps found in refineries throughout the nation. No data were submitted by the commenter to substantiate the contention that some pumps have distinctly lower leak frequencies. There may be many reasons that the lower leak frequency was found in his plant. One reason may be that a control program was recently implemented.

Skip-period monitoring for pumps has not been included in the standards for two reasons. The first is that pump seal failures are sudden events independent of prior leak history. Valve leaks (where skip-period monitoring has been used), in contrast, gradually increase over time, so that leak history is a factor in the leak status of any one valve. A skip-period monitoring program for valves achieves emissions reduction because the number of valves leaking gradually (and very slowly for process units that can use this alternative) increases over the monitoring period. However, skip-period monitoring for pumps would allow large emitters to leak for a long period of time because pump seals begin to leak suddenly. Secondly, the number of pump seals that must be monitored is not large enough to develop a meaningful statistical program. For example, a large process unit (Model Unit C) would only have about 40 pump seals in light liquid service. Hence, an allowable percentage of pumps leaking, for example 2.0 percent, would not even allow a single pump leaking. EPA has provided other alternatives to monthly monitoring, which include (1) installation of a properly designed dual mechanical seal as specified in Section 60.592(d), (2) installation of an enclosed capture/conveyance/control system as described in Section 60.592(f), and (3) use of leakless equipment as provided in Section 60.592(c).

Since proposal, the cost basis of leak detection and repair programs for pump seals has been revised to assess pump repair on a consistent basis with information presented in the AID (Document No. II-A-41). In the proposal BID, pump seal repair costs are based on 80 labor hours per pump seal repair. This basis has been revised to 16 labor hours per seal repair plus the cost of a replacement seal ($140/seal, May 1980 dollars). The cost effectiveness which appears in the preamble for the proposed standards has been revised to $158/Mg VOC emission reduction (Document No. IV-B-2). EPA believes the revised cost effectiveness for pumps is reasonable.

Comment:

Two commenters requested that there be exemptions for pumps. One of these commenters (IV-D-8) indicated that "some pumps may not be able to accommodate dual seals. Accordingly, the standards should provide exemptions from the requirement to install dual seals if 1) dual seals cannot be retrofitted to the existing pump, i.e., the pump would have to be replaced to install dual seals; and 2) if a compatible barrier fluid cannot be found." The other commenter (IV-D-12) indicated that certain reciprocating pumps should be exempt due to the prohibitive cost of bringing reconstructed reciprocating pumps into compliance. Also, if an owner or operator installs a dual seal, that pump should be exempt from routine monitoring.

Response:

EPA recognizes that some pumps may not be readily retrofitted with dual mechanical seals, although circumstances where a dual mechanical seal cannot be retrofitted without replacing the entire pump are rare.

An exemption for these few pumps is necessary. The standards do not require dual mechanical seals, but only require satisfactory performance under the leak detection and repair program. Leak levels below 10,000 ppm organic concentration at the surface (which remains the only requirement for pumps) may be obtained by replacing the original seal or the original seal packing. Should these measures fail to reduce the leak rate to an acceptable level (an intrument reading of less that 10,000 ppm), the seal area may be enclosed, and the enclosure vented to a control device.

Availability of compatible barrier fluids should rarely pose a problem. As discussed in the BID for the proposed standards (pp 3-4 through 3-6) dual mechanical seals may be arranged in either of two configurations, back-to-back or tandem. The tandem arrangement utilizes a barrier fluid pressure lower than the process fluid pressure at the pump seal, such that any leakage at the primary pump seal results in a leakage of process fluid into the barrier fluid. Such a sealing arrangement will prevent contamination of the process fluid by the barrier fluid. The barrier fluid must be purged, however, to a controlled degassing reservoir to prevent the leaked process fluid from eventually being emitted to the atmosphere. In the back-to-back arrangement the two seals provide a closed cavity between them and a barrier fluid is circulated through the cavity at an operating pressure greater than the stuffing box. Barrier fluid leaking across the primary pump seal will enter the stuffing box and mix with the process fluid. Barrier fluid going across the secondary seal would release to atmosphere unless captured by a vent control system.

Reciprocating pumps may also be maintained in compliance with the leak detection and repair program requirements. EPA recognizes, however, that maintaining adequate sealing for less than 10,000 ppm organics concentration around linear motion shafts may be difficult. However, the seal area (or distance piece) of such pumps may be enclosed, and the enclosure vented to a control device. As such, an exmption for these pumps is not necessary. The commenter provided no information or data to support the statement that costs of compliance for reciprocating pumps is prohibitive.

If an owner or operator chooses to utilize an alternative control technique for pumps such as dual seals or enclosed and vented seal areas rather than monthly monitoring, these pumps are exempt from the routine instrument monitoring. However, several criteria would need to be met for these alternative controls such as weekly visual inspections, continuous monitoring of the barrier fluid system for seal failure detection, and daily barrier fluid level checks. These are required to ensure the integrity of the alternative control system and to remain exempt from monthly monitoring. In order to clarify the intent of this requirement, the final regulation will include a definition for "stuffing box pressure" as "the pumped product pressure at the primary seal interface."

Comment:

One commenter (IV-D-14) expressed concern that the alternative standards for pumps "are essentially a barrier fluid standard because in the dual seal system, one mechanical seal is still exposed to the atmosphere, as is the case with a single mechanical seal. But requiring a dual seal system rather than defining the standard as the use of a non-VOC barrier fluid on the seal exposed to atmosphere, precludes the use of a single mechanical seal with the same barrier fluid even though the two are equivalent from the standpoint of emissions." The same commenter suggested that EPA simply establish a no detectable emissions limit for the barrier fluid system.

Response:

The commenter appears to be requesting an exemption from the routine leak detection and repair program for single seal pumps with non-VOC barrier fluids. EPA does not have enough information to use in evaluating such an approach, and the commenter did not suggest a means of ensuring continued compliance with the standards such as the barrier fluid requirements of the proposed standards. EPA does not know how to do this either. For these reasons, single seal/barrier fluid systems are not exempt from the standards.

The standards, however, allow owners or operators to use equivalent means of emission limitation as provided for in Section 60.484. An owner or operator subject to the standards may apply to the EPA for determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required by the standards. Each owner or operator applying for an equivalence determination is responsible for collecting and verifying test data to demonstrate equivalence.

EPA did not require a "no detectable emissions" limit for pump seals because with the control technique specified (monthly leak detection and repair) as the basis for the standards, pumps can still leak. Several types of pumps with auxiliary equipment (e.g., dual mechanical seals that utilize a barrier fluid system, and enclosure of the pump seal area), however, can achieve emission reductions of VOC at least equivalent to that achieved by a monthly leak detection and repair program for pumps provided that they are operated under certain conditions. Sealless pumps do not have a potential leak area and, therefore, are at least equivalent to monthly leak detection and repair and dual seal systems. As with other leakless equipment, sealless pumps would be subject to an initial performance test (using procedures specified in Reference Method 21) to verify that the piece of leakless equipment meets the "no detectable emissions" limit, and annual rechecks to ensure continued operation with "no detectable emissions."

Comment:

One commenter (IV-D-21) questioned Section 60.592.2(d)(i) that he said creates the requirement that barrier fluid be at a higher pressure than the stuffing box. The commenter said that this requirement is impossible because the "barrier fluid pressure is the stuffing box pressure."

Response:

As discussed in Chapters 3 and 4 of the BID for the proposed standards, dual mechanical seals consist of two seal elements with a barrier fluid between them. By pressurizing the barrier fluid to a pressure greater than the process pressure, any leakage in the primary seal would result in the leakage of barrier fluid into the process, while any leakage in the secondary (outer) seal would result in leakage of barrier fluid to the atmosphere. Provided a non-VOC barrier fluid is used, no VOC leakage to the atmosphere can occur.

The intent of §60.592-2(d)(1)(i) is that the barrier fluid be maintained at a higher pressure than the pumped product as discussed above. Where dual mechanical seals are used, several pressures are associated with the stuffing box, including the pumped product, the barrier fluid pressure, and the atmospheric pressure on the outside of secondary seal. Originally EPA intended to require that the barrier fluid be maintained at a pressure higher than the pumped product outlet pressure. However, the pressure of the pumped product at the primary seal face (i.e., at the stuffing box) may be different from the outlet pressure. As such, EPA decided to clarify the requirement by requiring that the barrier fluid pressure be greater than the pressure of the pumped product at the stuffing box. The terminology used by the EPA has led to the commenter's confusion. To clarify the requirement, in response to this comment, EPA will add a definition of "stuffing box pressure" to the final standards to indicate that the stuffing box pressure, for purposes of the standards, is the pressure of the product at the primary seal face.

2.3.2 Monitoring

Comment:

Two commenters (IV-D-8 and IV-D-21) wrote that the criteria for visual pump inspections should be revised. One commenter (IV-D-21) stated that liquid leakage from pumps should be defined in a more quantitative manner. The commenter suggested that the criteria be three drops per minute rather than the subjective "indications." Another commenter (IV-D-8) maintained that monitoring with an analyzer should be the sole criteria for determining a leak. In contrast, another commenter (IV-D-24) thought that monitoring of pumps is excessive and unnecessary because emission concentrations measured with a portable analyzer are erratic for mechanical seals. The commenter held that visual checks alone were an adequate means of detecting leakers.

Response:

The purpose of visual inspections of pump seals and barrier fluid systems is to detect leaks. Liquids dripping from the seal area indicate seal wear and may signal the beginning of seal failure or actual failure of the barrier fluid system. To prevent excessive wear that could possibly result in catastrophic seal failure, the seal should be repaired soon after leakage is detected. Visual inspections detect the leaks associated with such failures of seal systems. Therefore, any visible leakage from the seal area is considered a leak. A more quantitative approach, "such as three drops per minute," would be no more indicative of a leak than the approach proposed by EPA. However, to define better what EPA considers "liquids dripping," a definition has been added to the standards. "Liquids dripping" means any visible leakage from the seal including spraying, misting, clouding, and ice formation.

The results of the Western Oil and Gas Association (WOGA) testing of petroleum refining industry pumps (Document No. II-A-42) have shown that 44 percent of light liquid service pumps found exceeding the 10,000 ppm action level also had liquid leaks that were visually detected. Hence, visual inspections do find a significant proportion of "leakers" and are an effective supplement to instrument monitoring. However, large quantities of VOC can be emitted from leaking pump seals even when there is no visual indication of leakage. Large leaks can occur without forming liquid drops or obvious indications of liquids dripping. For example, emissions may be sprayed as a fine mist, vaporize, or may condense as ice. Thus, pumps require a more precise measurement method (i.e., the use of a monitoring instrument) to determine if emissions are equal to or greater than 10,000 ppm.

There is a relatively high degree of certainty whether a pump seal has an organics concentration at greater than or less than 10,000 ppm using Reference Method 21. Pump seal failures are usually sudden (not a deterioration effect), such that emission concentrations are either well above or below the 10,000 ppm leak definition for pump seals. Further, no data were provided by the commenters to support the contention that instrument measurements are erratic for pump seals. Hence, EPA maintains that instrument monitoring is effective and necessary to identify leaking pump seals.

2.3.3 Repairs

Comment:

Several commenters expressed concern about the repair of pump seals. Two commenters (IV-D-8 and IV-D-14) were concerned that a high portion of pump seals continue to leak in excess of 10,000 ppmv following attempted repair. Two commenters recalled that in the WOGA study

(Document No. II-A-42), the previously referenced industry pump seal testing, 40 percent of the pumps continued to leak after attempted repair, whereas, the cost effectiveness of the control technique is based on the presumption of 100 percent successful repair. Some commenters (IV-D-8, IV-D-15, and IV-D-18) requested that the regulations allow delay of repair for pump seals. One commenter noted that more than 6 months (as allowed in the proposed standards) is sometimes needed to retrofit dual seals. Also, delay beyond unit shutdowns should be allowed for pumps if there is a delay in equipment delivery.

Response:

Pump seal manufacturers have indicated (Document No. IV-E-4) that their emissions testing shows 10,000 ppm to be a proper leak definition criteria and that properly installed and operated seals should easily meet it. However, EPA recognized before the standards were proposed that repairing pump seals to achieve VOC emission concentrations to below 10,000 ppm may be difficult in some instances. The specific reference to the WOGA study (Document No. II-A-42), that "40 percent of the pumps repaired continued to leak", does not necessarily apply to the standards for pumps. Pumps with new seals, especially seals of harder material, may have a run-in time of up to 48 hours of operation to seat properly (Document No. IV-B-17). There is no evidence given in the WOGA study to indicate that some of the pump seals that continued to leak following repair were not monitored within the run-in period. Seal replacement may in fact have been a much more successful means of repairs, and reported as such, if pump rechecks were measured after the run-in period. Also, in this study, pump seal repair was not always seal replacement (e.g., tightening of seal packing), whereas the EPA cost analysis was based on seal replacement.

EPA analyzed control techniques for pumps that might not be repairable to below 10,000 ppm. The cost effectiveness of installing a dual mechanical seal with a barrier fluid system was examined for pump seals that (1) are known to be leaking and (2) cannot be repaired by relatively simple procedures (such as replacing a seal). Based on this, EPA found the cost effectiveness of installing dual seals to reduce pump emissions to be reasonable (Document No. IV-B-5). EPA expects the use of dual seal systems to comply with the repair requirements of the proposed standards. However, because retrofitting these systems cannot be completed in 15 days, EPA provided 6 months to complete the repair. Owners and operators also have the option of enclosing the pump seal and venting the emissions to a control device.

In response to the second group of commenters, EPA recognizes the need for delay of repair if the repair necessitates process unit shutdown. However, delay of repair for pumps beyond unit shutdown is not necessary because the plant owner or operator can stock (without unreasonable costs) enough spare seals and seal parts for repair to prevent shortage of seal parts due to a delay in equipment delivery. EPA proposed to allow delay of repair beyond shutdown for valves that require replacement of the entire valve assembly if the owner or operator shows that a sufficient stock of these assemblies had been maintained before the stock was depleted. However, there are substantially fewer pumps in process units than valves, so stocking spare seals is not unreasonable. In addition, most refineries have a spare pump in place that can be operated while the leaking pump is being repaired so it is not clear why many repairs would ever need to be delayed to a process unit shutdown. EPA, therefore, does not consider it necessary to incorporate the delay of repair provision into the final standards for pumps.

Commenters were concerned that they would not be able to retrofit dual mechanical seal systems within the required 6-month period (Section 60.592-2(c)(3)) for leaking pumps that cannot be repaired to achieve emission concentrations below 10,000 ppm. However, pump seal manufacturers (IV-E-6 and IV-E-8) have indicated that the 6-month requirement to retrofit a dual mechanical seal system is reasonable. Most dual mechanical seals can be shipped from the manufacturer the day they are ordered, and, in the event of an unusual or special order, dual seal systems can be manufactured in 16 to 18 weeks. Twenty-four weeks (6 months) would allow for engineering and installation. A refinery may have some difficulty with installing more than 10 dual seal systems in a given 6-month period. However, EPA does not expect that more than 10 dual seals will be installed in a single process unit during a given six-month period. Thus, EPA considers the decision to allow owners or operators to delay repair of pumps up to 6 months reasonable if a dual seal system must be used.

2.4 COMPRESSORS

Comment:

One commenter (IV-D-12) commended EPA for providing exemptions for existing reciprocating compressors.

Response:

EPA did not provide a blanket exemption for existing compressors in the proposed standards as the commenter implied even though EPA discussed that certain reciprocating compressors might not be covered under the reconstruction provisions if retrofitting the required equipment was technologically or economically infeasible (see 40 CFR 60.15(e)). To make EPA's intent clear and to reduce the burden of reviewing reconstruction determinations, EPA is explicitly exempting existing reciprocating compressors provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance. This exemption is necessary because the cost impact of installing the required control equipment or replacing the compressor is unreasonable. These compressors will be exempt from the standards until they are replaced by new compressors or the distance pieces are replaced.

Comment:

Another commenter (IV-D-30) was concerned that a case-by-case determination of the feasibility of putting controls on reconstructed reciprocating compressors would be burdensome to EPA or the States and would probably result in a blanket exemption. The commenter requested that EPA reexamine whether a specific definition of the compressors that are appropriate to exempt can be written in lieu of the case-by-case determination.

Response:

It is impossible to fully define all applications of reconstruction considered for existing reciprocating compressors. EPA maintains, however, that the determination of technological or economic feasibility (or infeasibility) to meet the standards would not be burdensome for EPA (or State agencies delegated enforcement authority), considering the few compressors that might fit into this exemption. The exemption applies only to those specific instances where the seal area cannot be enclosed and vented without recasting the distance piece or replacing the compressor.

EPA has evaluated (Document No. IV-B-20) means of controlling compressor leaks that may comply with the standards for compressors at reasonable cost. Based on the availability of reasonable control options, EPA does not believe that the provisions for reciprocating compressors will result in a blanket exemption of all such compressors.

Comment:

A commenter (IV-D-14) argued that the standards for compressors do not provide an incentive to improve existing control technology. Another commenter (IV-D-8) wrote that "there is no justification for establishing a separate and arbitrary definition of leak for compressors," thus EPA should use the 10,000 ppm leak definition. Other commenters (IV-D-14 and IV-D-16) asked EPA to allow quarterly monitoring as in the refinery CTG (Document No. II-A-6).

Response:

The standards for compressors do not deter the incentive to improve existing control technology. Refiners have the option of employing mechanical seals with barrier fluid systems and controlled degassing vents or may alternatively enclose the seal area and vent the captured emissions to a control device. These are generally the only techniques available to reduce VOC emissions from compressor seals. In addition, the standards provide additional flexibility and incentive to improve upon existing technology through the provisions of Section 60.592-3(i) that allow an automatic equivalence for no detectable emissions. Furthermore, an owner or operator may apply equipment or procedures that achieve a reduction in VOC emissions at least equivalent to the reductions achieved by the compressor control requirements.

The standards for compressors require the use of mechanical seals with barrier fluid systems and controlled degassing vents. Leakless equipment is allowed as an alternative to the mechanical seal system. Leakless equipment is considered at least equivalent to mechanical seals if they can be shown to have no emissions. Method 21 defines no emissions, or "no detectable emissions," as a minimal deflection of the portable instrument meter. In the case of the proposed standards, this is a reading of 500 ppm or less. Hence, the 500 ppm is not a leak definition as misconstrued by the commenter, but an instrument limited definition of no detectable emissions as specified in Reference Method 21.

Quarterly monitoring is not allowed under the standards because it would achieve significantly less emission reductions than the mechanical seal system, other leakless control, or enclosure and venting to a control device. Even as noted in the refinery CTG published in June 1978 (Document No. II-A-6), EPA has concluded that a leak detection and repair program for compressors in refineries is generally not an effective control technique and, therefore, EPA did not consider it a viable option as the basis for the standards. Quarterly monitoring was recommended in the refinery CTG due to the limitations of retrofitting equipment controls on existing compressors. The effectiveness of a leak detection and repair program for compressors is limited because repair of leaks for most compressors could not be accomplished without a process unit shutdown and because some seals must leak to operate properly. Because shutdowns generally occur infrequently, limiting the emission reduction obtained from maintenance, and because repair of a compressor seal would often involve the use of mechanical seal systems or enclosure and venting to a control device, equipment controls are used as the basis for the standards. These equipment controls have a reasonable cost effectiveness (see preamble for the proposed standards, Table 1).

2.5 PRESSURE RELIEF DEVICES

Comment:

One commenter (IV-D-19) was concerned that the costs for rupture disks are overestimated in the BID for the proposed standards. The commenter said: (1) EPA costs are based on relief valves with the rupture disk offset under it; this practice and cost is not necessary and violates recommended industry codes; (2) the added cost for retrofitting a disk and valve is only valid for half of the field installations because the downrating of a valve as an ASME requirement is only mandatory for new installations and is not required for retrofit installations; and (3) in a recent API survey, half of the companies responded that they already use block valves under relief valves; therefore, the block valve really should not be included in the cost of installing a rupture disk under a relief valve. Another commenter (IV-D-12) disagreed with EPA's decision to require rupture disks for pressure relief valves. The commenter thought the incremental cost of $930 per megagram emission reduction from quarterly leak detection and repair to the use of rupture disks was unreasonable. The commenter recommended quarterly leak detection and repair as an alternative control for pressure relief valves.

Other commenters remarked concerning disk sizing. One commenter (IV-D-14) urged EPA to consider a case-by-case standard for pressure relief devices because problems in sizing spool and piping are likely to arise as a result of added pressure drop in retrofit installations. Another commenter (IV-D-19) in contrast wrote that most rupture disks manufactured have flow coefficients (0.95 and higher) compatible with relief valves manufactured, so that it is becoming common practice not to downrate relief valves upon retrofitting rupture disks.

Response:

The basis of the standards selected for pressure relief devices in gas service is the use of rupture disks. Rupture disks eliminate fugitive emissions of VOC through the relief device unless an overpressure occurs. After an overpressure release, replacement of the rupture disk once again eliminates fugitive emissions of VOC through the pressure relief device. Therefore, a "no detectable emissions" standard was selected for pressure relief devices. The proposed standards for pressure relief devices require that they be operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and that they return to this condition within 5 days following pressure release.

At proposal, EPA considered the incremental cost effectiveness between quarterly monitoring (required by State implementation plans) and rupture disks (see preamble for the proposed standards, Table 1) and determined that the resulting value, $930/Mg VOC, was reasonable. The commenter disagreeing with the reasonableness of this incremental cost effectiveness has offered no specific information suggesting that this cost effectiveness level is unreasonable.

In reviewing the public comments, EPA re-evaluated (Document No. IV-B-2) the cost effectiveness and incremental cost effectiveness of different levels of control (quarterly and monthly leak detection and repair and the use of rupture disks) for pressure relief devices as shown in Table A-2 of Appendix A. The cost effectiveness for quarterly and monthly leak detection and repair was estimated to result in savings of $170/Mg VOC and $110/Mg VOC, respectively. The use of rupture disks has a cost effectiveness of about $410/Mg VOC. The incremental cost effectiveness between quarterly and monthly leak detection and repair is about $250/Mg VOC. The incremental cost effectiveness between monthly leak detection and repair and rupture disks is about $1,000/Mg VOC.

At proposal, EPA cost estimates were based on rupture disks with offset mounting to prevent damage to the relief valve by disk fragments as stated in the BID for the proposed standards, Table 8-1. EPA recognizes that the offset mounting may not be necessary, and that it could present a safety problem if it added significant pressure drop to the system. In these cases, EPA agrees that an offset mounting would not or should not be used. However, since owners or operators might use the rupture disks with offset mounting, EPA did not revise the basis for the rupture disk system costs, realizing that the estimated costs to comply with the standards may be overestimated.

The first commenter was also concerned that block valves should not be included in the cost analysis because they are already installed in half the refineries surveyed by API. Even though the use of block valves may already be widespread, EPA expects that some refiners would use them in the absence of the standards, and, therefore, EPA decided to continue to include them in the cost analysis. This will result in an overestimate of the nationwide cost impact of the standards for pressure relief devices.

Sizing problems in retrofitting rupture disks can be avoided through the selection of compatible disks and disk holders; therefore, there is no reason to establish special requirements for pressure relief devices in process units affected through modification or reconstruction. In addition, refiners have the option of venting pressure relief valve emissions to a VOC control device, such as a flare.

Comment:

Two commenters (IV-D-8 and IV-D-21) stated that rupture disks should not be used as the basis for judging the leak rate of pressure relief valves because rupture disks are not common in the industry as mentioned in the BID for the proposed standards.

Response:

EPA is required to establish new source performance standards based upon best demonstrated technology (BDT), not common technology. EPA has determined that rupture disks represent BDT for pressure relief devices.

The standards for pressure relief devices are based on the use of rupture disks. Because rupture disks eliminate emissions, EPA selected a performance standard of "no detectable emissions."

Comment:

Commenters (IV-D-5, IV-D-8, and IV-D-18) were concerned with the safety of the standards for pressure relief devices. Monitoring pressure relief devices is inherently unsafe. In addition, these components are frequently difficult-to-monitor. The practice of employing rupture disks is unsafe due to the pressure build-up between the disk and relief device.

Response:

Refineries routinely inspect pressure relief devices approximately on an annual basis as a part of normal safety and maintenance procedures to ensure the set pressure is correct (Document No. II-D-22); therefore, the standards are not requiring refineries to do a new task. The standards implicitly require performance tests using Method 21 to verify that the device is maintained at no detectable emissions. This test is similar to testing done by EPA and EPA contractors in collecting data for development of the standards and similar to testing required by States under implementation plans. This test could be scheduled during periodic inspections of pressure relief devices, which are typical of many industry safety practices. Monitoring should be done by personnel who understand the precautions needed when monitoring pressure relief devices. Evidence that operators can safely monitor pressure relief devices is further indicated by one refiner's (Document No. IV-D-33) practice of removing pressure relief devices (for repair/replacement and testing) following overpressure releases. Based on this information and EPA's experience in collecting data for pressure relief devices, monitoring of these devices can be done safely.

The standards for pressure relief devices are based on the use of rupture disks; however, the standards do not require their use. Alternatively, pressure relief device emissions can be routed to a VOC control device, such as a flare. If a rupture disk is used, a pressure sensor should be installed to warn operators if a pressure increase has occurred between the disk and relief valve. The cost of a such a sensor (0.6 cm pressure gauge) has been included in the cost analysis that is presented in the BID for the proposed standards, Chapter 8, Table 8-1.

Comment:

Two commenters (IV-D-8 and IV-D-21) disagreed with the leak definition for pressure relief devices stating that there is no justification for a different leak definition than 10,000 ppm.

Response:

The standards for pressure relief devices are based on the use of certain equipment. This equipment, as explained in the preamble to the proposed standards, results in no detectable emissions. The no detectable emissions limit is 500 ppm according to Method 21 and is related to monitoring instrument capabilities. The 10,000 ppm leak definition for pumps and valves was chosen based on different considerations and is unrelated to standards that require no detectable emissions, such as the standards for pressure relief devices. A 10,000 ppm or greater concentration indicates a pump seal failure or deterioration of a valve packing, and concentrations below 10,000 ppm are allowed. The no detectable emissions level (500 ppm) indicates no emissions.

Comment:

Another commenter (IV-D-21) requested the addition of a qualifying phrase to the standards, Section 60.592-4(b), such that pressure relief valve monitoring only be required "after each pressure relief, of which the operator has knowledge." The commenter wrote that this clause is necessary because pressure relief to the atmosphere is not always known by the owner or operator.

Response:

The intent of the standards for pressure relief valves is to control emissions at all times except during an overpressure relief. Therefore, the standards require that pressure relief valves return to no detectable emissions as soon as practicable, but no later than 5 calendar days after the pressure relief. Pressure sensors between the rupture disk and pressure relief device can alert operators in the event of a pressure relief. Owners or operators may also be alerted that pressure release has occurred from instrumentation in a unit control room or by visually or audibly detecting a release.

2.6 SAMPLING SYSTEMS

Comment:

A commenter (IV-D-14) wrote that an exemption in the proposed standards for sampling systems should be allowed when for example, a sample might be drawn after a heat exchanger or cooler, and there is not enough pressure available to return it to a lower pressure source. The commenter suggested an alternative to closed loop sampling. He recommended simply to require accumulation of the purged material in another container for proper disposal. Another commenter (IV-D-4) maintained that the application of the standards for sampling connection systems for "low vapor pressure liquid streams is not cost effective with respect to reduction of VOC emissions."

Response:

The standards do not require "closed loop" sampling (although it may be used to comply with the standards) but do require a "closed purge system" as one commenter suggested. Using closed purge sampling, an owner or operator could simply collect purged materials and properly dispose of them by any system that collects the VOC and destroys or recovers the VOC without emissions to atmosphere.

EPA recognizes that some sampling connections are located at points that would have insufficient pressure to return purged fluid in a closed loop. For example, low line pressure (resulting from pressure drop in the final product coolers or a phase change) is characteristic near plant boundaries. Hence, EPA expects that owners/operators would use closed purge to comply with the standards. If a plant owner or operator chooses to retrofit a closed loop sampling connection in these instances at a location of higher pressure (e.g., near a pump), and if a sample cooler is not in place at the selected location, a cooler may have to be installed to ensure safe handling of hot materials.

Retrofitting a closed loop sampling connection at a location that necessitates a cooler, however, is not expected to occur often. Most sampling connections are located near pumps where line pressure is not a problem and where cooling systems are already in place (Document No. IV-B-6). Nevertheless, EPA has estimated the additional cost of retrofitting a closed loop sampling system with a cooler. The addition of a sample cooling system increases the cost effectiveness of the sampling system from $810/Mg to $1,450/Mg.

The standards for sampling connections include low vapor pressure liquid streams. Heavy liquid streams have the potential to emit VOC's to atmosphere, particularly from purged sampling materials that are likely at elevated temperatures. The emission factor developed for sampling connections is based on both light liquid and heavy liquid streams. The cost effectiveness estimate of $810/Mg is based on closed loop sampling. However, the standards allow closed purge sampling which would likely be used for low vapor pressure streams at an even more reasonable cost effectiveness.

Comment:

Another commenter (IV-D-4) suggested an exemption for sampling connections in units that become affected facilities through modification or reconstruction if retrofit costs exceed that of a comparable installation in a new unit.

Response:

The control costs presented in Chapter 8 of the BID for the proposed standards for sampling systems are likely overstated because they are based on closed loop sampling. These costs included retrofit considerations. The cost effectiveness of closed loop sampling is estimated to be $810 per Mg (preamble to the proposed standards). It is possible, however, that in some situations retrofit costs for using closed loop sampling will exceed that of the cost of a new sampling system. [The example given in the previous comment indicated that owners/operators may retrofit a closed loop sampling system by adding a sampler cooler. Although it is unlikely that retrofitting a closed loop sampling connection at a location that necessitates a cooler would occur very often, EPA evaluated the cost effectiveness to retrofit a closed loop sampling system by adding the cost of a dedicated sample cooler. EPA determined that the cost effectiveness of the system is still reasonable, $1,450 per Mg VOC (Document No. IV-B-6).] If a specific plant would incur extra costs, EPA would not consider this unreasonable.

2.7 OPEN-ENDED LINES

Comment:

One commenter (IV-D-8) questioned the operational requirement of closing the inner valve prior to closing an outer valve on open-ended lines. The commenter wrote that this requirement is unenforceable and of no benefit if the inner valve leaks.

Response:

The standards require open-ended valves to be equipped with a cap, plug, or a second valve. If a second valve is used, the upstream valve is required to be closed first before closing the downstream valve. This operational requirement is merely sound practice that plant operators currently follow to prevent process fluid from being trapped between the valves. While it is true that this and many other sound practices are not 100 percent enforceable, this requirement is enforceable if an inspector finds that the upstream valve has not been closed at all.

If hot (or cold) product is trapped between the two valves, as it contracts (expands) from cooling (heating) to ambient temperature, it could cause the pipe, the valve stem, or the valve seat to fail. Should the inner valve leak through the valve seat, however, the product will eventually fill the piping between the valves with ambient temperature fluid without stressing the valve seat. In this situation the second valve would control VOC emissions.

Comment:

Another commenter (IV-D-14) recommended that open-ended valves and lines be included in the valve standards (i.e., leak detection and repair) with an exemption for plugged valves. The commenter was concerned that any open-ended valve could result in a violation. Concern was also expressed that requiring plugs on pump case valves could cause premature failure of the welded connection at the pump case. Also, the standards would require plugging bleed valves "out-of-service" in a block and bleed arrangement.

Response:

Open-ended valves are not included in the valve standards because leak detection and repair for open-ended valves does not represent BDT. Leak detection and repair would achieve less emissions reduction and may cost more to implement than the equipment and operational standards for open-ended valves because of repeated inspections of nonleaking sources. The use of a leak detection and repair program for the control of VOC emissions from open-ended valves or lines would be inappropriate.

The standards for open-ended valves provide refineries with the flexibility to add either a cap, plug, blind flange, or a second valve depending upon the individual application. Pump case valves, for example, could be double valved to avoid the risk of premature failure of the welded connection at the pump case caused by frequent removal of a cap or plug.

Upon reviewing the comment that the standards would require plugging bleed valves "out-of-service" in a block and bleed arrangement, EPA decided to provide an exemption in the final standards for open ended lines in a double block and bleed arrangement when venting the space between the two block valves. However, when the bleed valve is not opened, it must be capped.

2.8 FLANGES, LIQUID SERVICE RELIEF VALVES, AND HEAVY LIQUID SERVICE VALVES AND PUMP SEALS

Comment:

One commenter (IV-D-8) maintained that the results of a number of studies support an exemption for equipment in low vapor pressure service. The commenter noted that an EPA study (Document No. II-A-19) of two refineries in the South Coast Air Basin had monitored 664 components in light and heavy liquid service (which were exempt from South Coast Air Quality Management District rules) and found only four leaking components, none of which were in heavy liquid service. Another study found only one leaking valve out of 519 in heavy liquid service and only 3.8 percent of the pumps leaked. Another commenter (IV-D-15) also supported excluding pumps in heavy liquid service, pressure relief valves in light liquid service, flanges, and connections from routine monitoring.

Another commenter (IV-D-21) wrote that there is no demonstrable cost effectiveness to the inclusion of pumps and valves in heavy liquid service, pressure relief devices in both light and heavy liquid service, and flanges and other connections, and further, these sources should be exempt from all requirements as indicated by EPA at the National Air Pollution Control Techniques Advisory Committee (NAPCTAC) meeting on June 3, 1981.

Response:

The final standards for valves and pumps in heavy liquid service, pressure relief valves in liquid service, flanges, and connections exempt these sources from routine leak detection and repair. The low leak frequency and emission factors for these sources compared to sources subject to the leak detection and repair programs, as discussed at the June 1981 NAPCTAC meeting, indicate that the cost of routine leak detection and repair is not warranted by emission reduction. However, Section 60.592-8 provides that if evidence of a potential leak is found, the piece of equipment must be monitored within 5 days, and repaired as soon as practicable within 15 days if an instrument reading of 10,000 ppm or greater is detected.

For those components that are found leaking, however, EPA has demonstrated that the cost effectiveness of repair is reasonable. (Document No. IV-B-5). The cost effectiveness of repair for leaking flanges, heavy liquid pumps, and heavy liquid valves varies from a savings of about $180/Mg to a savings of about $90/Mg. For pressure relief devices in liquid service, repair costs are not considered to be attributable to the standards. These components should be properly maintained for safety reasons in the absence of a repair requirement.

The SCAQMD regulations for valves, Rule 466.1, do not cover VOC less than or equal to 1.5 psi RVP. The NSPS, however, includes valves that are less than 1.5 psi RVP. In reviewing the commenter's request to exempt these valves, EPA notes that these valves do leak. An EPA study [Document No. IV-A-3] found that 3 of the 175 light liquid valves with vapor pressures less than 1.5 psi RVP leaked. In addition, raising the heavy liquid service cutoff to 1.5 psi RVP would affect a small percentage of valves. In the study previously cited, the 175 valves represented only 2.4 percent of the total valves that would be subject to the standards. Hence, considering: (1) that the basis of the heavy liquid/light liquid split is easily determined, (heavy liquids have vapor pressure equivalent to or heavier than kerosene), (2) that light liquid valves servicing less than 1.5 psi RVP streams do leak, and (3) that a small percentage of refinery valves would be affected, EPA has retained the light liquid definition.

2.9 CONTROL DEVICES

Comment:

One commenter (IV-D-21) wrote that since flares are not an affected facility or a fugitive emission source they should not be regulated.

Response:

Flares are one of several VOC control devices that might be used to comply with the standards. These control devices are used to reduce emissions of VOC that might otherwise be emitted to the atmosphere uncontrolled. If flares and the other control devices were not specifically regulated they might be operated at conditions which would result in inefficient combustion and inadequate emission reductions. The EPA has determined that a flare can be operated at conditions which assure better than 95 percent emission reduction. Flares operated in this way are an acceptable alternative to other control devices used to comply with the standards. Section 111(h)(1) provides that EPA may promulgate design and operational requirements (like the requirements in these standards for other control devices) to assure BDT - level control and that EPA include such requirements as will assure proper operation and maintenance of any such element of design or equipment. Therefore, it is appropriate to specify operational requirements for flares used to comply with the control device standards developed under Section 111(h)(1).

Comment:

Several commenters (IV-D-4, IV-D-8, IV-D-12, and IV-D-15) requested that the requirements for flares be deleted, including the provision that compliance be determined by Reference Method 22. They recommended that they be replaced with provisions that flares function in accordance with good operating practice with an attached flame and no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

Response:

Data developed by a Chemical Manufacturers Association (CMA) - EPA flare test program (Document No. II-A-43) show that some types of flares meeting certain conditions achieve better than 98 percent emission reduction. Consequently, the EPA concluded that design and operational standards which require flares to be operated at the conditions determined by the tests would assure better than the required 95 percent emission reduction. The term "good operating practice" has no accepted engineering meaning. There is no evidence that flares give better than the required 95 percent emission reduction at all velocities at which the flame remains "attached." Therefore, requiring that flares function in accordance with good engineering practice with an attached flame does not assure better than the required 95 percent emission reduction. The standards do require that there be no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. Reference Method 22 describes the procedure used to determine whether the flare meets this visible emission requirement.

Comment:

Several commenters (IV-D-6, IV-D-7, IV-D-8, IV-D-15, and IV-D-16) wrote that the definition of a "flare" was too restrictive and should be revised to allow many flare designs which are currently in use in refineries. The commenters specifically opposed the definition because: (1) multiple burner arrays are efficient, (2) there is no relationship between destruction efficiency and flare elevation, and (3) most flares operate with turbulent diffusion flames rather than strict diffusion flames. One commenter also stated that the definition should allow automatic ignition systems.

Response:

The definition of a flare is restrictive in that the types of flares permitted are limited to those on which data are available. Other types of flares may give better than the required 95 percent reduction under certain conditions. EPA has underway a program to determine the efficiencies of some other types of flares used in the petroleum and SOCMI industries. As this information becomes available to EPA, the requirements for flares could be changed, if it is appropriate. If an owner or operator chooses to use another type of flare, he may use the equivalency procedures to demonstrate that the flare should be allowed by EPA. EPA accepts that there is no relationship between flare destruction efficiency and flare elevation. Accordingly, the definition of control device has been changed to exclude the term "elevated." Also, automatic ignition systems are not disallowed by the regulation.

Comment:

Other commenters (IV-D-6, IV-D-7, IV-D-15, and IV-D-16) urged EPA to revise the design and operational requirements for flares. The commenters noted that the maximum velocity of 22 m/sec would greatly increase flare costs. It was also suggested that the assignment of minimum heating values for flares be related to the relief gas composition.

Response:

The maximum velocity value of 22 m/sec was changed since proposal to 18 m/sec. This change was based on further evaluation of the data. The revised exit velocity (for steam assisted flares), is the highest velocity tested in the flare tests sponsored by CMA and EPA (Document No. II-A-43). EPA has underway a program to determine if better than the required 95 percent emission reduction can be maintained at higher velocities. If EPA concludes that high emission reduction can be maintained at velocities greater than 18 m/sec, EPA will change the maximum velocity value accordingly. An operator would have the option of demonstrating to EPA that use of a flare at conditions other than those specified, would result in emission reduction equivalent to 95 percent control, the level selected as BDT for control devices.

Comment:

One commenter (IV-D-25) stated that flares should be exempted during start-up and shut-down periods and for 10 minutes during a 2-hour period. Even under ideal conditions, unit upsets may cause incidents exceeding the 5 minutes per 2 hours exemption for visible emissions. One commenter (IV-D-6) suggested that EPA clarify that a visible flame does not constitute a visible emission.

Response:

Start-up and shut-down periods and any "unit upset" due to malfunctions are covered by the General Provisions. Section 60.8(c) states that "Operations during periods of start-up, shut-down, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of start-up, shut-down, and malfuction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard."

The 5-minute limit for visible emissions (within any 2-hour period) is consistent with the flare requirement of the State of Texas where many plants with smokeless flares are located. EPA has no information, nor has any been submitted in this rulemaking, suggesting that these plants cannot achieve this time limit.

The standards require that Reference Method 22 [Section 114 of the Clean Air Act as amended (42 U.S.C. 7414)] be used to determine the compliance of flares. This method involves the visual determination of visible smoke emissions from flares. Section 3.4 of Method 22 clearly states that "smoke occurring within the flame, but not downstream of the flame, is not considered a smoke emission."

Comment:

Another commenter (IV-D-24) objected to the requirement for instrumentation to monitor flare operating parameters.

Response:

With respect to instrumentation to monitor flare operating parameters, an owner or operator is only required to use a heat sensing device to indicate the continuous presence of a flame. Flares and other control devices are required to be operated at all times when emissions may be vented to them. Other measurements for flares are required one-time only or when requested by enforcement agencies for a compliance determination.

Comment:

A commenter (IV-D-8) requested that the requirement of Reference Method 22 be deleted because fugitive emissions from flares are small, and existing flares are designed on a different basis.

Response:

As explained in the preamble to the proposed standards, EPA selected design and operational requirements for VOC control devices: flares, enclosed combustion devices, and vapor recovery systems that reflect the application of the best technological system of emission reduction for these control devices. The design and operation requirements for flares require smokeless operation. Smokeless operation of a flare means that visible emissions from a flare are to be less than 5 minutes in any 2-hour period as determined by Reference Method 22. Reference Method 22, hence, provides guidelines for assessing visible emissions from flares and is included in the standards to ensure that flares achieve greater than 95 percent control.

Comment:

One commenter (IV-D-30) believed that EPA has not adequately justified rejection of flares as the sole basis for the standards for control devices. The commenter stated there was no cost analysis in the BID to support EPA's belief that flares are too costly if they are built solely for fugitive VOC control. The commenter contended that, where point sources of VOC and fugitive sources are controlled by a single flare, 98 percent control efficiency should be required.

Response:

Existing control devices were selected as part of the best technological system of emission reduction for fugitive emission. EPA believes that most in-place flares and enclosed combustion devices are designed and can achieve an average destruction efficiency of about 98 percent. Existing vapor recovery systems can be operated to achieve at least 95 percent emission reductions and are an attractive control option in that some product may be recovered and realized as an energy credit (e.g., process heaters). Flares were not selected as the sole basis for this portion of the standards, as the commenters requested because the cost of requiring owners and operators to replace 95 percent efficient control devices already in place in existing refineries with

98 percent efficient devices is unreasonably high in light of the small additional emission reduction achievable from these equipment leaks. The standards, therefore, require 95 percent control (which allows use of existing vapor recovery systems that can achieve 95 percent, but not 98 percent control in all cases) although EPA expects that most refiners will utilize flares and achieve 98 percent or better control.

3.0 APPLICABILITY

3.1 AFFECTED FACILITY

Comment:

Two commenters (IV-D-8 and IV-D-21) questioned whether an "affected facility" should be defined as a group of fugitive emission sources of VOC, noting that (in their opinion) the definition is inconsistent with the terms of the Clean Air Act. A commenter (IV-D-21) stated that Regulation 40 CFR 60.2 requires that an "affected facility" be an apparatus and "a group of fugitive sources is not an apparatus." These commenters implied that all equipment (including equipment not affected by the requirements of the standards) should be included in the affected facility for process units. One commenter (IV-D-8) stated that the control of fugitive emissions is significantly different from controlling emissions from new stationary sources generally covered by NSPS. Fugitive emissions control "involves continuous tightening or repairing of thousands of individual components, each of which emits relatively small amounts of emissions," whereas with most other stationary sources subject to NSPS, "once the control equipment is installed routine maintenance is generally required." Based on these positions the commenters stated that control of fugitive emissions through new source performance standards is unworkable.

Response:

In choosing the designation of affected facilities, EPA examined fugitive emission sources of VOC in light of the terms and purpose of Section 111 of the Clean Air Act. The Clean Air Act mandates the EPA to set standards for any pollutant emitted from a category of new or modified "stationary sources." Section 111(a)(3) of the Act defines the term "stationary source" to mean "any building, structure, facility, or installation which emits or may emit any air pollutant." The pieces in VOC service of equipment in a process unit, viewed in the aggregate, are a "facility" that may emit air pollutants and, therefore, are appropriately considered as a "stationary source".* How these pieces of equipment are or are not aggregated into affected facilities is carefully considered by EPA.

Since the purpose of Section 111 is to minimize emissions by application of the best demonstrated system of emission reduction at new and modified sources (considering cost, nonair quality health and environmental impacts, and energy requirements), there is a presumption that the narrowest designation (i.e., individual pieces of equipment) is proper. However, EPA rejected the equipment component designation for fugitive emission sources other than compressors; this decision is discussed in response to another comment in this section (see page 3-6). Consequently, the next most narrow definition, the group of all equipment components (except compressors) within a process unit, was considered. Review of the relevant statutory factors did not lead to the conclusion that designating each group of equipment components in a process unit as an affected facility would cause adverse impacts. Defining an affected facility as the group of equipment components, other than compressors, within a process unit would achieve similar emission reductions as designating individual components as the affected facility. (See discussion in comment on this point.) Therefore, the affected facilities for the standards are (1) compressors in petroleum refineries and (2) the group of equipment (pressure relief devices, open ended lines, sampling systems, valves, and pumps) in a process unit.

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*This agrees with the dictionary definition of "facility," meaning something designed, built, installed, ect., to serve a specific function or perform a particular service" (The Random House College Dictionary, Revised Edition, 1975). The group of equipment in VOC service covered by these standards is designed and installed to serve the specific function of handling the processing of petroleum products into intermediate or more refined materials.

We note in this regard that the Court of Appeals for the District of Columbia Circuit has stated that:

> In designating what will constitute a facility in each particular industrial context, EPA is guided by a reasoned application of the terms of the statute it is charged to enforce, not by an abstract "dictionary" definition. This court would not remove this appropriate exercise of the agency's discretion.

578 F.2d 319, 324 n. 17 (1978). EPA's selection of the group of fugitive VOC emissions-related equipment as the affected facility reflects a reasoned application of Section 111. It assures that an identifiable subset of refinery emissions--equipment leaks of VOC-- is controlled as soon as the equipment responsible for those emissions is either modified, reconstructed, or newly constructed. For the reasons explained in the text below, a broader definition (e.g., all the components of a process unit) would simply delay that result.

Some of the commenters appear to be suggesting that the affected facilities should include equipment within a process unit even though the equipment is not an apparatus to which the standards apply. Such an approach would mean equipment affected by the standards would not be required to use the best demonstrated technology (considering costs). EPA believes this approach would be inconsistent with Section 111. (No evaluation of the best demonstrated technology (considering costs) has taken place for these equipment at this time. EPA may evaluate this for these equipment later.) Also, if EPA would follow this approach, increases in emissions from emission points not affected by the standards and changes in operation not related to the equipment covered by the standards could result in modifications. In contrast, emission reductions resulting from the incremental control of emission points not covered by the standards could be used to offset increases in emissions resulting from emission points covered by the standards and, therefore, would preclude what otherwise might have been a modification. EPA believes this approach would be confusing. Based on this consideration, EPA rejected this approach.

The commenter stated that control of fugitive emissions through standards of performance is unworkable because the fugitive emission sources covered by the standards do not include all of the equipment within a process unit. This is a practical consideration only when considering the modification and reconstruction provisions in Part 60. For newly constructed sources, the standards are clearly practicable. The standards are well defined and will result in the intended purpose of requiring the best demonstrated technology for equipment leaks of VOC (fugitive emission sources of VOC). For an owner or operator who might be considering or determining a modification or reconstruction, however, this definition might pose some difficulties. For example, determining the basis (see definition of capital expenditure--40 CFR 60.2) of an existing facility is more difficult for this standard than for most other standards of performance (See Section 4.0 for more examples). EPA has provided alternative approaches to reduce the burden associated with these difficulties. These alternative approaches were not provided to make this definition usable but to make it easier to use. This issue and the alternative approaches are discussed further in Section 4.0 and, to the extent it concerns the reconstruction provisions, in Section 5.0.

Comment:

Another commenter (IV-D-30) contended that EPA should define the affected facility as each individual fugitive emissions component based on "Section 111's presumption for inclusiveness." In addition, the commenter did not believe that EPA provided convincing reasons to support the decision to treat compressors individually and other components collectively (process units) in defining "affected facility." The commenter contended that EPA's first reason for rejecting individual components (the cost of tracking individually covered sources) is not persuasive because a simple color coding or tagging of new and existing components could be used. Additionally, in response to EPA's second reason for rejecting individual components as the basis for the affected facility, the commenter indicated that it does not appear that there would be a significant difference in leak detection and repair costs between the "process unit" definition and the "individual component" definition of affected facility. This commenter also stated that he found no evidence in the preamble or the BID for the proposed standards for EPA's assertion that the "process unit" definition of affected facility would achieve as much emission reduction as the "individual component" definition. The commenter believed that as individual components are added to a unit, they are covered earlier and achieve further emission reductions than fugitive emission sources within process units, which are not covered by the standards until the entire unit is replaced.

Response:

In selecting the basis for the affected facility, EPA considered the effects of keeping track of individually covered sources. As discussed in the preamble to the proposed standards, components in existing plants would be replaced one at a time and, therefore, would be covered by the standards one at a time. Because components in existing plants are infrequently replaced, many adjacent components would not be covered by the standards. This would mean that a plant would be required to inventory all the components in a plant and then keep track of all activities for each component. Even though individual components could be color coded or tagged, EPA believes that the effort to keep track of and record activities for a mixture of individual components within a plant would be tedious and costly. In addition, as discussed below, EPA believes that this effort would not likely result in additional emission reductions, in particular, during earlier implementation of this approach. In contrast to the recordkeeping effort for individually covered sources, the effort for components within process units would be less and would still result in more immediate emission reductions. Thus, EPA judged that maintaining an inventory of individual components for an entire plant would be unreasonably burdensome, but maintaining an inventory for compressors or evaluating components occasionally within process units would not be unreasonably burdensome.

The commenter appears to have misunderstood the techniques used to determine the cost effectiveness for leak detection and repair programs. The costs incurred for implementing such a program include fixed costs, for example, the monitoring instrument and calibration costs which are shared by the components monitored. The fixed costs can be unreasonably high if only a few components are monitored. Additionally, EPA costs are based on a specific time required for monitoring each component. These monitoring times are based on the normal physical distribution of components in petroleum refining process units. If only a few components scattered throughout a plant are monitored, the time required per component would be greatly increased. These monitoring costs would be unreasonable until enough components would be covered within a certain area of a plant. This area may be smaller than a process unit but not significantly smaller than a process unit.

In response to the commenter's concern about emission reductions, EPA attempted to select a basis for the affected facility definition that would provide the largest emission reduction that is reasonable. As discussed above, EPA most seriously considered two approaches in defining the affected facility--the individual "component" approach and the "process unit" approach. The largest emission reductions are usually associated with a component basis. However, for these standards the difference between emission reductions of the component and process unit approaches are unclear. Based on the "component" approach all new components--covered by the standards--and all replaced components would be affected by the standards. A modified component would be unlikely. [The replaced components would be scattered throughout the plant and would become affected by the standards one at a time as existing components are replaced.] In contrast, under the process unit approach, all new components within "new" process units would be covered by the standards, but individually replaced components would not be covered. Most importantly, many components (not actually increasing emissions or being replaced) in modified process units or reconstructed process units would be covered ("captured") based on the "process unit" approach.

The difference between the emission reduction potential for the two approaches can be based on the difference in the number of individually replaced components and the number of components that are "captured" in modified or reconstructed process units. EPA believes that, in this case, the numbers are similar. However, there is no reliable procedure to approximate these numbers. Based on EPA's belief that the emission reductions between the component approach and the process unit approach are similar and based on the burden associated with maintaining records of individual components for an entire plant, EPA selected the process unit as the basis of the affected facility for all the equipment covered by the standards except compressors.

Comment:

Three comments were received concerning the designation of compressors as a separate affected facility. One commenter (IV-D-10) supported compressors as a separate affected facility; however, others (IV-D-5 and IV-D-12) maintained that when compressors are an integral part of a process unit they should be considered part of the "process unit" affected facility. When compressors are not considered an integral part of a process unit, they should be considered separately. Also, commenters said designating compressors as a separate affected facility could lead to confusion and would likely make them subject to standards sooner because they are often replaced at shutdown.

Response:

As discussed in the preamble to the proposed standards, compressors (unlike other fugitive emission sources in petroleum refineries) are major pieces of equipment and are readily identifiable. Since compressors are relatively few in number, tracking of those subject to NSPS requirements and those not subject to these requirements would not be difficult. As mentioned above, there is a presumption that the narrowest definition of an affected facility is proper unless there is a statutory factor that leads EPA to a less narrow definition. Commenters did not present any of these factors. The fact that compressors are integral to the process unit does not preclude EPA from defining them as separate affected facilities. By extension, the commenter's reasoning would prohibit EPA from defining different emitting sources within a plant as separate affected facilities because they are integral to the plant. It is clear, however, that EPA has authority under Section 111 to define each as a separate source. Moreover, EPA has often chosen such plant subsets as separate affected facilities. (For example, see Subpart Da of 40 CFR Part 60 -- each boiler at the utility station is a separate affected facility). Focusing on whether equipment is integral to a process simply is not helpful or relevant to the selection of the affected facility for purposes of standards of performance.

It should be noted that by making compressors a separate affected facility, compressors are not likely to be covered by modification provisions. However, as one of the commenters stated, when a compressor is refurbished or replaced it would likely be a reconstruction and, therefore, covered by the NSPS. EPA considers this appropriate. EPA considered the comments received regarding designation of compressors as separate affected facilities and concluded that the designation should remain for the same reasons originally stated in the preamble to the proposed standards.

Comment:

One commenter (IV-D-10) recognized that the definition of process unit includes flexibility and that determinations of an affected facility may be on a case-by-case basis. The commenter wrote that the identity of a "process unit" is not always clear or equally transferable from one refinery to another.

Response:

EPA agrees with the commenter that there will be differences in "process unit" affected facilities, even among processes producing the same petroleum product. Thus there is flexibility in the definition of process unit. These differences are mainly caused by differences in design and construction of process units. Typically, equipment within a process area is functionally related and associated with a single process unit. However, some equipment pieces (generally, very few) within an area may be functionally associated with a second process unit that is not located in the area. Hence, equipment function will be a determining factor as to which process unit it is considered to be in. When a piece of equipment can function in more than one process unit, its location will be a determining factor. It should be noted that owners and operators may request EPA to review plans for construction or modification for the purpose of obtaining technical advice, as provided in the General Provisions of Part 60 (40 CFR 60.6).

3.2 DEFINITION OF "IN VOC SERVICE"

Comment:

Several commenters (IV-D-6, IV-D-8, IV-D-16, IV-D-21, and IV-D-24) requested that the definition of "volatile organic compound (VOC)" specifically state which organic compounds are excluded. It was also recommended that the definition include the phrase, "or as measured by the applicable test methods described in Reference Method 21."

Response:

Volatile organic compounds (VOC) are defined as organic compounds that participate in photochemical reactions. Any organic compound is presumed to participate in atmospheric reactions unless the Administrator determines that it does not. EPA considers several organic compounds to have negligible photochemical reactivity. These are methane, ethane, 1,1,1-trichloroethane, methylene chloride, trichlorofluoromethane, dichlorodifluoromethane, chlorodifluoromethane, trifluoromethane, trichlorotrifluoroethane, dichlorotetrafluoroethane, and chloropentafluoroethane.

The standards provide for the exclusion of substances considered non-photochemically reactive by EPA from the percent VOC in the process fluid when determining whether a piece of equipment is not in VOC service. The purpose of this is to avoid covering those sources that have only small amounts of photochemically reactive substances in the line and to establish the standards consistent with the data base. In determining whether the VOC in a process line is less than 10 percent of the total mass in the line (as a prerequisite to determining that a piece of equipment is not in VOC service), quantities of compounds present in the line that are considered nonphotochemically reactive by EPA may be excluded from the total quantity of organic material.

Section 60.595(d) of the standards requires that VOC content is to be determined by the referenced ASTM methods, not by Reference Method 21. The referenced ASTM methods can be used to distinguish among compounds and, therefore, allow the determination of the amount of photochemically reactive compounds in a process stream. In contrast, Reference Method 21 is a method for determining leaks. This method requires that monitors used in complying with the standards respond to the organic compounds in the process streams. Thus, there is no reason to include the phrase requested by the commenter.

Comment:

Several commenters (IV-D-8, IV-D-12, IV-D-18, IV-D-21, IV-D-22, and IV-D-24) requested that the proposed definition of "in VOC service" be revised. The commenters suggested raising the weight percent cutoff from 10 to 20 weight percent VOC to exclude coverage of hydrogen service compressors and to provide more reasonable operating flexibility. Excluding 75 volume percent or greater hydrogen streams and changing the 10 weight percent VOC to 10 volume percent VOC were also recommended. The commenters contend that such streams would have a lower percentage of VOC and, consequently, the controls would achieve lower VOC emission reductions and have a higher cost effectiveness ($/Mg VOC emission reduction).

Response:

The commenters are suggesting that EPA exempt equipment that, because they contain so few VOC, are not cost effective to control. In response to this comment, EPA analyzed the control of valves and compressors in hydrogen service (Document No. IV-B-9). Most process streams affected by the standards are clearly above 10 weight percent VOC, and many are nearly 100 weight percent VOC. Process streams less than 10 weight percent are almost always much less than 10 weight percent VOC. Only a few process streams may be near 10 weight percent VOC, and these are generally those that would be considered in hydrogen service. Thus, EPA analyzed the control of equipment that, based on EPA's data, could be found in hydrogen service. This would allow EPA to exempt control of equipment if it is not cost effective. In hydrogen service is defined as greater than 50 volume percent hydrogen based on EPA's data. The analysis is explained in docket item IV-B-9. Emission reductions are achieved for valves in hydrogen service at reasonable costs ($106/Mg VOC). However, application of equipment controls for compressors in hydrogen service results in a cost effectiveness of $4,600/Mg VOC. EPA, therefore, decided to exclude compressors in hydrogen service from the standards.

In EPA's judgment, determination of VOC content in a given stream is a routine analytical procedure. The test method, ASTM E-260, gives quantitative measures of each component proportional to their concentration. Hence, the results are expressed as a weight percent. The commenter recommending that the VOC content expressed in weight percent be changed to a volume percent did not provide any basis for this change. Hence, EPA maintains that the VOC content expressed in weight percent is a reasonable approach.

Comment:

Another commenter (IV-D-21) remarked that the definition of VOC fails to establish a de minimis level for volatile materials which do not contribute to atmospheric emissions. A "heavy liquid" definition was considered necessary because it would avoid unnecessary monitoring of components processing materials that are unlikely to register a 10,000 ppm concentration.

Response:

The definition of VOC does not exclude compounds based on volatility. Processes that produce relatively non-volatile products can involve high temperature and pressure conditions, thus producing emissions of VOC. These VOC contribute to ozone formation. A *de minimis* level would not be appropriate. EPA has tailored the standards (in part, based on volatility) to require the best demonstrated technology. As a consequence, EPA concluded that routine leak detection and repair is not warranted for components in heavy liquid service because they have low leak rates and, as a group, control is not cost effective (Docket No. IV-B-5).

Heavy liquid streams are generally a mixture of heavy hydrocarbons (e.g., crude oil) with very little light hydrocarbons. Nevertheless, these streams have the potential to leak VOC (determined by concentrations in excess of 10,000 ppm), and these VOC would contribute to ozone formation. Data reviewed by EPA (Document No. II-A-19) show that a few components in heavy liquid service do have emission concentrations greater than 10,000 ppm and, therefore, do leak emissions of VOC. When these leaks occur, repair is cost effective (Document No. IV-B-5). If an operator sees, hears, smells, or otherwise suspects a leak, it is appropriate that the component be monitored and, if a leak exists based on a greater concentration, that it be repaired.

Comment:

One commenter (IV-D-12) supported the proposed definition for "light liquids" as it agrees with findings in their fugitive emissions program, however, another (IV-D-17) held that the definition was too restrictive and should include only the heavy naphthas and lighter materials because as defined, some equipment in light liquid service would not significantly contribute to fugitive emissions. Excluding compounds with a Reid Vapor Pressure (RVP) less than 1.5 psi was recommended.

Response:

The criterion used by EPA for the light liquid definition (that is, liquids with a vapor pressure greater than that of kerosene) was based on fugitive emission data gathered in petroleum refinery studies (Document No. II-A-19). Equipment processing VOC with vapor pressures greater than kerosene were found to leak at significantly higher rates and frequencies than equipment processing VOC with vapor pressures of kerosene or lower. Therefore, EPA decided to exempt equipment processing VOC substances with vapor pressures lower than about the vapor pressure of kerosene from the routine leak detection and repair requirements of the standards. This is consistent with the commenter's request to cover only heavy naphthas and lighter compounds.

The RVP cutoff of 1.5 psi that was recommended by the commenter is based on California regulations for the storage of volatile organic liquids which are at ambient pressure and temperature. There are no data to support the 1.5 psi cutoff as it would apply to fugitive emission sources. EPA considers control of equipment in light liquid service (based on the proposed definition) cost effective; therefore, based on these considerations, EPA did not revise the definition of light liquid service.

3.3 EXCLUSIONS

Comment:

One commenter (IV-D-13) stated that process units with in-place state-of-the-art hydrocarbon gas detection systems should be exempted. This commenter requested that units in an arctic environment be exempted because of several unique aspects of refining in the North Slope of Alaska. For example, (1) the products are used locally, (2) process units are totally enclosed at a high cost because of the harsh environment; therefore, present safety controls (gas detector placed near exhaust fans with an alarm set at 12,500 ppmv) are adequate and additional requirements are unwarranted, (3) requiring rupture disks ahead of pressure relief devices would compromise safety especially under this application, (4) repair labor is 2 1/2 to 4 times more costly, and (5) control of VOC has limited benefit in attainment areas, especially in the arctic where cold ambient temperatures, the degree of insolation, and a low concentration of photochemical precursors limit ozone formation.

Response:

The presence of an in-place state-of-the-art hydrocarbon gas detection system does not necessarily ensure emission reductions. Gas detection systems set for 12,500 ppm would permit VOC to be emitted without notice. Several megagrams of VOC would be released to the atmosphere annually without the use of specific control techniques like those required by the standards. The commenter did not demonstrate that their system resulted in at least equivalent emission reductions as the standards. Upon request by EPA, the commenter explained the specific control techniques used at their plant, many of which are identical to those required by the standards. Based on EPA's experience, gas detection systems alone are ineffective for reducing equipment leaks of VOC. Thus, EPA has not exempted process units using these systems from the standards. The final standards do, however, allow an existing control program to be continued if EPA determines that the program is at least equivalent to the requirements of the standards.

EPA has studied the commenter's concerns and acknowledges that there are several unique aspects to refining in the North Slope of Alaska. Accordingly, EPA concluded only that the costs to comply with the routine leak detection and repair requirements of the proposed standards may be unreasonable. These operations incur higher labor, administrative, and support costs associated with leak detection and repair programs, because (1) they are located at great distances from major population centers, (2) they must necessarily deal with the long term extremely low temperatures of the arctic, and consequently (3) they must provide extraordinary services for plant personnel. These unique aspects make the cost of routine leak detection and repair unreasonable (Document Number IV-B-15). Therefore, EPA has decided that refineries in the North Slope of Alaska are exempt from the routine leak detection and repair requirements of the standards. This exemption does not include the equipment requirements in the standards because the cost of those requirements is reasonable.

Comment:

One commenter (IV-D-26) recommended that the definition of "petroleum refinery" be clarified to exclude production and intermediate facilities such as wells, drill pads and separation tanks, that may be involved in onsite processing in oil fields. Similarly, another commenter (IV-D-3) requested that the definition of "petroleum" be revised to clarify that coal tar and refined coal tar oils that are by-products of coking processes are not covered in these standards because they are not covered under Subpart J.

Response:

In Section 60.591 (Definitions), the proposed standards defined "petroleum refinery" as "any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum, through the redistillation, cracking, or reforming of unfinished petroleum derivatives." This definition does not include production and intermediate facilities found in oil fields, nor does it include production tar and tar oils from coal coking processes. The standards apply only to process units within petroleum refineries. New source performance standards (NSPS), however, are being developed by EPA for the natural gas processing industry under another standards development project (40 CFR Part 60 Subpart KKK - Standards of Performance for Onshore Natural Gas Processing Plants: Equipment Leaks of VOC). The natural gas processing industry NSPS may cover fugitive emission sources at production, and will more likely cover them at intermediate facilities. EPA has consistently used the term "petroleum"; it does not mean tar and tar oils from coal coking processes, but it does mean synthetic petroleum products from processes that use coal as a raw material. Thus, EPA has not clarified the term "petroleum." It should be noted that the production of some chemicals (for example, formaldehyde or phenols) at coal coking processes, however, is covered by NSPS for the synthetic organic chemical manufacturing industry (Subpart VV).

Comment:

Another commenter (IV-D-8) maintained that the results of a number of studies support a complete exemption for equipment in low vapor pressure service. The commenter noted that an EPA study (see Document No. II-A-41, p. 2-38) of two refineries in the South Coast Air Basin had monitored 664 components in light and heavy liquid service (which were exempt from South Coast Air Quality Management District rules) and found only four leaking components, none of which was in heavy liquid service. Another study found only one leaking valve out of 519 in heavy liquid service and only 3.8 percent of the pumps leaked. Another commenter (IV-D-15) supported excluding pumps in heavy liquid service, pressure relief valves in light liquid service, flanges, and connections from routine monitoring.

Another commenter (IV-D-21) wrote, however, that there is no demonstrable cost effectiveness to the inclusion of pumps and valves in heavy liquid service, pressure relief devices in both light and heavy liquid service, and flanges and other connections, and further, these sources should be exempt from all requirements as indicated by EPA at the National Air Pollution Control Techniques Advisory Committee (NAPCTAC) meeting on June 3, 1981.

Response:

The commenters suggest that certain types of equipment leak so infrequently that it is not cost effective to monitor them for leaks. The final standards for pumps in heavy liquid service, pressure relief devices in light liquid service, flanges, and connections exempt these sources from routine leak detection and repair because of the low leak frequency and emission factor for these sources as discussed at the June 1981 NAPCTAC meeting. However, the commenters have suggested no reason that this equipment, if found to be leaking, cannot be repaired cost effectively. EPA has determined that it is cost effective to repair these components if they are leaking (see Document No. IV-B-5). Therefore, Section 60.592-8 provides that if evidence of a potential leak is found, the piece of equipment must be monitored within 5 days, and repaired as soon as practicable within 15 days if an instrument reading of 10,000 ppm or greater is detected.

3.4 SMALL REFINERS

Comment:

Commenters (IV-D-9 and IV-D-23) accused EPA of incorporating into the standards a bias against small refiners. They asserted that small refiners will be affected more adversely than will large refiners. There is a bias, they reason, because EPA did not analyze the comparative impact of the standards on large versus small refineries. The comparative analysis was not done because EPA, citing elimination of the crude oil entitlements program, decided that relatively little new unit construction will occur at small refineries, and even considering modified and reconstructed units, few small refineries would be subject to the standards. Thus, the commenters claim, EPA saw no reason to give small refineries special attention under the Regulatory Flexibility Act. Therefore, a bias exists. One commenter (IV-D-9) said some small refineries have existed for more than 40 years and are viable without subsidy programs. Thus, both commenters conclude, EPA should have analyzed the differential impact of the standards on small refineries compared with large ones.

Response:

To analyze the economic impacts of the standards, EPA defined 12 types of refinery units: crude distillation, hydrotreating, isomerization, etc. (See BID for the proposed standards, Document No. III-B-1). Each type was assigned to one of three model unit categories. Model Unit A has a small number of pumps, valves, and other components; Model Unit B has a larger number; and Model Unit C has the most. Assignment of each type of unit to a particular model unit category was based on equipment counts averaged over units found at a range of refineries. EPA then assumed a reasonably small throughput (which might be representative of some small refineries) for each type of unit, because small-throughput units would show significant adverse economic impacts much more readily than large-throughput units would for any given amount of money to be spent on controlling fugitive leaks. If the analysis had revealed potential, adverse economic impacts, EPA would have intensified its examination of the units involved, and possibly would have changed the standards appropriately. However, no such impacts were projected. EPA concluded that no adverse economic impacts would result from the standards and that there was no need to extend the economic analysis to cover a wider range of throughput levels.

The Regulatory Flexibility Act (Public Law 96-354, September 19, 1980) requires that special consideration be given to the impacts of standards on small firms. As one criterion for extending loans and related assistance, the Small Business Administration defines a small petroleum refining firm as one employing fewer than 1,500 workers (13 CFR Part 121, Schedule A). The 1,500 number applies to the entire firm, including affiliates, and is tied in with other criteria relating to throughput capacity, exchange agreements, and the like. EPA accepts this definition of a small refiner. Based on this definition, EPA projected few small firms would be affected by the standards. However, even for those affected by the standards, EPA concluded that the impacts would be reasonable.

The commenters implied that small process units or refineries may be owned by small firms. However, there are no available data that relate the size of refining firms (number of employees, throughput, etc.) to the size of their individual refinery units (number of valves, pumps, etc.). In addition, there is no reason to believe that the size of a refining firm is necessarily related to the size of its individual refinery units. EPA, therefore, has no basis to suspect that small firms will bear greater compliance costs than large firms on an affected facility-by-affected facility basis. In fact, the impacts are similar for all sizes of units. The three model units differ only in regard to their respective equipment counts. Compliance costs for Model Unit A, the smallest, are lower than compliance costs for Model Unit C, the largest. Even though the cost effectiveness for Model Unit A is larger than it is for Model Unit C. However, these cost effectivenesses are not significantly different. The commenters offered no evidence that the sizes of their units, measured either by throughput or by equipment counts, will cause the impact of the standards to fall disproportionately on small firms, or that small firms will become non-competitive, or that small firms will be forced to raise prices substantially.

EPA's projection that relatively few units at small refineries will be affected by the standards by 1987 is still valid. If, for some reason not now anticipated, the standards were to place a disproportionate burden on small refineries, the 1987 projects indicate that comparatively few such refineries would experience that burden and, more importantly, the cost estimates indicate that none of those refineries would experience unreasonable costs. [EPA regrets that its statement may have been interpreted by the commenters as a bias against small refiners.]

Comment:

One commenter (IV-D-22) remarked that economic conditions in the refinery industry have changed drastically since 1980, that the projected number of affected facilities is now too high, and that the benefits of the proposed standards, therefore, are overstated.

Response:

EPA projected that 100 new and 182 modified or reconstructed units would become affected facilities during the first 5 years of implementation of the standards. The commenter offered no alternative projections to supplement the claim that 282 units are too many. There are three reasons why EPA believes the projections should not be changed.

First, the projections in no way affect the need for standards or the selection of the final standards. The projections are offered only as a guide for understanding the future aggregate costs and emission impacts of the standards. Ideally, the projections should be conservative. However, being conservative requires EPA to project minimal growth when estimating emission impacts, and to project maximal growth when estimating aggregate costs to the nation. Low projections can understate possible economic costs, but high projections can overstate emission savings. The middle ground reflects EPA's best judgment, considering these two conflicting uses for the projections. Furthermore, if all projected growth does not occur by the end of the fifth year, it will occur sometime shortly thereafter.

Second, the projections were made for the calendar years 1982 through 1986. For reasons unforeseen when the projections were prepared, the proposal of the standards was delayed a year. This means that the projections should now be interpreted as applying to the years 1983 through 1987. This shift of 1 year moves the projection interval completely out of the 1981-1982 economic downturn that the commenter believes caused the projections to be overly optimistic. As general economic recovery proceeds, there is every reason to believe the recovery will be felt throughout the refinery industry.

Third, the projection methodology used by EPA excludes modification and reconstruction at refineries with crude distillation capacity under 2,226 m^3 (14,000 bbl) per calendar day. This exclusion was made as a way of accounting for the possible effect of elimination of the crude oil entitlement program. Nevertheless, two commenters (IV-D-9 and IV-D-23) representing small refiners complained that there would in fact be more modification and reconstruction than EPA projected. Thus, there is an indication that the projections are, if anything, too low in this area.

For the above reasons, EPA is not revising the projection of new, modified, and reconstructed refinery units.

4.0 MODIFIED SOURCES

4.1 EMISSION INCREASE

Comment:

A number of commenters (IV-D-14, IV-D-15, IV-D-16, and IV-D-21) requested that the EPA allow an increase of a de minimis level of emissions before an existing facility would be considered to have modified. De minimis values of 5 tons per year and 40 tons per year (as in 40 CFR 51.18(j)) were suggested by the commenters.

Response:

Under the definition in Section 111(a)(4), any physical or operational change resulting in an increase in emissions constitutes a "modification." EPA has exempted certain small emissions increases from consideration in deciding whether there has been an increase in emissions constituting a "modification" for purposes of PSD applicability (40 CFR 52.21(b)(2) and (b)(231)). This action followed the decision in Alabama Power Co. v. Costle, 636 F.2d 323 (D.C. Cir. 1979), in which the D.C. Circuit held that EPA has authority to interpret the definition of "modification" so as to exempt sources with small emissions increases from PSD review on grounds of administrative necessity (Id. at 400).

The Alabama Power decision does not require EPA to provide a de minimis exemption from application of the "modification" definition for NSPS applicability purposes. Nor has EPA's experience in implementing the NSPS program suggested an administrative need for relieving existing sources from NSPS applicability when they undergo changes resulting in only a small increase in emissions. This differs somewhat from EPA's implementation of the definition of "modification" for PSD applicability purposes. In that area, the Agency has determined that the administrative burden of applying the full preconstruction review process to a source with only a small emissions increase may be unreasonable (45 FR 52705; August 7, 1980). The administrative burden associated with the NSPS program, however, is relatively minimal. In contrast to PSD requirements, NSPS's are categorically applicable technology-based requirements only; they do not involve an assessment of ambient effects and do not require case-by-case review.

Furthermore, EPA believes that the current straightforward application of the "modification" definition for NSPS purposes best serves Section 111's intent. One key purpose of the NSPS program is to prevent new pollution problems from arising. One way that the statute seeks to achieve this is by requiring application of the best demonstrated technology at, and thereby minimizing emissions from, existing facilities with increased emissions. The current NSPS approach of not providing an exemption from the "modification" provision based on the size of the emissions sources is not intended to cover existing plants making routine and minor additions. The "modification" provisions in the General Provisions of 40 CFR Part 60 exempt changes such as additions made to increase production rate (if they can be accomplished without capital expenditure, as defined in the General Provisions) and routine replacements (40 CFR 60.14(e)). In addition, these standards would exempt additions made for process improvements if they are made without incurring a capital expenditure.

Comment:

Other commenters (IV-D-8 and IV-D-14), concerned about the complexity of the modification provisions, endorsed revising the modification provisions such that a modification occurs when the number of components exceeds 10 percent of the total number of the same type and there is a net increase in emissions from the process unit.

Response:

As discussed in Section 4.2, EPA is promulgating an alternative procedure that will reduce the complexity of the modification provisions (in particular, how to determine a capital expenditure). In EPA's view 40 CFR 60.14 of the General Provisions adequately specifies the categories of changes to an existing facility that should bring the facility under NSPS as a "modified" source. It should be noted that, under Section 60.14(e), certain changes made in an affected facility without a capital expenditure are not considered "changes in operation" by EPA and, therefore, are not modifications. See, e.g., 40 CFR 60.14(e)(2)--production rate increases.

As proposed in the standards, certain changes (process improvements) made in an affected facility without a capital expenditure are not considered "changes in operation" by EPA and, therefore, are not modifications. This generally excludes coverage from industry practices that involve adding a few valves and maybe a sampling system and making other minor changes in equipment configurations. The 10 percent increase in the number of fugitive emission components as suggested by the commenter, would most likely be associated with a VOC emissions increase of about 10 percent. Making such a change would likely be associated with capital expenditure and, therefore, EPA considers this a modification. Therefore, EPA did not revise the modification provision as requested.

Comment:

Another commenter (IV-D-8) maintained that once a "modification" has occurred, the NSPS requirements should be applied only to those types of components which trigger the definition of modification.

Response:

Under Section 111 of the Clean Air Act, the application of modification is inextricably tied to the designation of "new source," or in NSPS terminology, an affected facility. Section 111(a)(2) defines the "new source" subject to NSPS as a source on which modification has commenced after proposal, not the portion of the source actually changed. Stated differently, modification provisions are triggered with respect to the affected facility; therefore, applicability is to all components affected by the standards within the affected facility. The commenter is implicitly requesting EPA to define the affected facility as a group of one type of equipment within a process unit. EPA, as discussed in Section 3.1, reasonably concluded that affected facilities to which the standards apply should remain: (1) the group of all fugitive emission sources (pumps, valves, sampling connections, pressure relief devices, and open ended lines) within a process unit and (2) compressors.

4.2 CAPITAL EXPENDITURES

Comment:

Commenters requested that the capital expenditure determination (as it relates to the modification provisions) be revised so that it is more practicable. Commenters (IV-D-8 and IV-D-15) remarked that the capital expenditure guidelines are outdated and would be difficult to use because units have been substantially rebuilt over the years and records of costs for determining the cost basis may be kept on a process unit basis rather than for individual pieces of equipment, or simply may not exist. It is, therefore, very difficult to reconstruct original costs.

In support of their concern about using original costs, the commenters stated that, based on EPA's current interpretation of capital expenditure, 1 to 3 percent of the current replacement costs would subject units to modification. Another commenter (IV-D-14) claimed that component costs represent 5 percent of the total original costs and that the addition of a new pump with several valves could easily exceed the "capital expenditure" definition. This commenter provided the hypothetical example of a unit with a total original cost of $16 million and component cost of $815,000. The addition of a pump with several valves would exceed 4 percent of the total component costs, around $56,000.

One commenter (IV-D-10) suggested that replacement costs rather than original costs be used to determine the basis for capital expenditure. A few commenters (IV-D-4, IV-D-15, and IV-D-16) suggested that capital expenditure be defined as 7 percent of the replacement cost (based on the Chemical Engineering Construction Index or other suitable index) of an affected facility at the time of process improvement.

Response:

After reviewing the comment letters concerning the difficulties with using the capital expenditure definition, EPA agrees that the definition for capital expenditure may be difficult to use for some refineries. Accordingly, EPA decided to provide an alternative to the procedures in the General Provisions. Although the implementation of the capital expenditure definition has been made more practicable, the original intent of the definition has been maintained.

The alternative uses an adjusted annual asset guideline repair allowance (AAGRA) and the replacement costs to determine capital expenditure. The adjusted AAGRA is determined by a formula and is based on a ratio that reflects inflation of costs over the last several years. The adjusted AAGRA is multiplied by the replacement costs of the equipment within the facility to determine the value of a capital expenditure.

The burden associated with using the capital expenditure definition in the proposed standards was not quantified by the commenters; however, if some of these problems can be resolved without changing the application of the modification provisions, EPA finds no reason not to do so. Accordingly, EPA is providing an alternative method to the General Provisions.

As mentioned above, the alternative method for determining capital expenditure enables refiners to use replacement costs rather than original costs. An inflation index can be applied to the replacement value of an affected facility to approximate the original cost basis of the affected facility. The relationship between replacement and original costs has been determined (Document Nos. IV-B-4 and IV-B-14) as:

$Y = 1.0 - 0.575 \log (X)$, where:

Y = the percent of the present replacement cost which is equivalent to the original cost, and

X = the year of construction.

Using the above equations and the annual asset guideline repair allowance (AAGRA) of 7 percent (see IRS Publication 534, page 20), capital expenditure can be expressed in replacement dollars as:

Capital Expenditure = $R \times Y \times 0.07$, where:

R = existing facility replacement cost.

Another alternative method that was considered is similar to that of the first in that an inflation index, Y (as defined above), and the AAGRA basis of 7 percent are used to allow refiners to use replacement costs. However, this second alternative would also allow refiners to use the cost of the entire process unit rather than the affected facility (the fugitive emission components). The second alternative would reduce the number of units that would use a detailed costing of equipment. However, the equipment covered by the standards represent a variable portion of the total costs of all the equipment in a process unit. Therefore, it is not practicable to assign a single percentage that would reflect the modification costs contributed by fugitive emission pieces. Thus, EPA is not adopting this alternative.

Even though EPA was unable to establish an alternative that would allow refiners to use the cost of the entire process unit, EPA would consider estimations from refiners that clearly show that an expenditure would be less than the quantity associated with a capital expenditure. There may be a variety of ways that these estimations can be made. For example, a refiner may have proof that in certain units 5 percent of the total replacement value at the process unit is the value of the equipment covered by the standards. If an estimation clearly demonstrates its results, EPA could quickly decide whether a process improvement involves a capital expenditure. Based on the example, if the value of the process improvement may be 0.04 percent of the replacement value of the process unit, this would be clearly less than 12.5 percent of 5 percent of the value of the total unit. If an estimation does not clearly show its results, then the time and effort required by EPA in evaluating the estimation would not provide the owner or operator a quick response and, therefore, a more-detailed costing of equipment (either by estimating replacement or accounting existing equipment) would be the owner or operators best approach. If EPA can judge easily--through review of a clear demonstration that a process improvement does not involve a capital expenditure, it will do so. In contrast, if EPA's review raises concerns or questions, EPA will reject the estimation unless further convincing support is presented.

Comment:

One commenter (IV-D-8) wrote that the General Provisions exempt "process improvements" from being considered modifications if made without incurring a capital expenditure; however, using the proposed definition of "capital expenditure" limits the exemption. Another commenter (IV-D-21) recommended deleting the modification provisions which require that process improvements be accomplished without a capital expenditure.

Response:

The General Provisions do not include a "process improvement" exemption. However, in the proposed standards EPA stated its intent that minor modifications would not be covered by the standards: "addition or replacement of fugitive emission sources for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart." The capital expenditure criterion was included so that minor process improvements in a process unit that cause an increase in emissions would not subject an existing facility to this NSPS. After reviewing these comments, EPA has maintained the same exemption. EPA considers any increase in emissions that results from a process improvement with a capital expenditure a "modification" unless one of the other exceptions in the General Provisions applies.

It should be noted that any potential emission increase that results from changes in operation that require the addition of a few fugitive emission sources could be offset or nullified by controlling existing equipment or installing components with no fugitive emissions. Accordingly, there would be no modification in such a case even if the emissions occurred with a capital expenditure. The standards do not require that process improvements be made without a capital expenditure. They merely provide an exemption when the process improvements are made with such an expenditure.

Comment:

One commenter (IV-D-30) argued that the "no capital expenditure" exemption for modifications could be construed by a plant as including, for example, the addition of fugitive components from existing inventory of spare parts. The commenter requested that EPA make it clear that the addition of equipment already in stock is still considered in determining a capital expenditure.

Response:

As discussed in the response to the previous comment, the capital expenditure criterion applies to process improvement or production rate increase exemptions that are considered when determining whether an increase in emissions at a facility results in a modification. This criterion is used to judge if the activity results in a change in operation. As such, a capital expenditure is determined by what is added to a process unit, not by what is purchased. Accordingly, it makes no difference whether the item was already in stock when the process improvement occurred.

4.3 SMALL FACILITIES

Comment:

Commenters (IV-D-9 and IV-D-23) stated that small refiners more easily trigger the modification and reconstruction provisions of the standards than do large refiners. A small capital expenditure on a small unit would cause the unit to be classified as "modified" more easily than the same expenditure would cause a large unit to be so defined. Some commenters (IV-D-8 and IV-D-15) also remarked that the definition of "capital expenditure" would impact small facilities more severely.

Response:

The provisions of the standards can be triggered by several different actions. Some of these actions are relative changes that are considered important because they involve a certain percent of the cost of the unit. Other triggering actions are absolute changes that are considered important because they involve an absolute increase in air pollutant emissions from the existing unit. Even if the reconstruction and modification provisions are more burdensome on small refineries, the overall impact of the standards is still reasonable, however. If the commenter's claim is true, then there must be a difference between units at small refineries on the one hand, and those at large refineries on the other. The difference could be related to size, age, ability to respond to today's changing markets, or myriad other factors. The question of unit size, measured by throughput or equipment count, is discussed in a previous response; the relationship between unit size and firm size is not clear. In general, small changes can trigger the provisions for units with comparatively few pumps and valves. However, it is not clear that the capital expenditure criterion would be exceeded quicker by a small process unit than by a large process unit. It is not necessarily true that the cost of a given set of equipment would be the same for a small and large process unit. Large process units can use large equipment or small equipment (the costs of which would be related, in a very general sense, to the size of equipment) and small process units can use large or small equipment. The value of any one pump in a process unit may be relatively small or large depending on the specifications in a particular application, not solely on the size of the pump. The commenters did not mention specific small refinery characteristics that would explain why small refiners might suffer a greater burden than large refiners. Age and obsolescence of equipment, the most obvious characteristics, do not appear to be significant factors. There are no data to indicate that units in need of modernization are situated predominantly at small refineries. Even if there are differences and small refineries are disproportionately affected, EPA does not consider this unreasonable because EPA believes that the standards are appropriate for all existing facilities that become affected by the standards.

For these reasons EPA concludes that the modification and reconstruction provisions of the standards will not subject small refiners to unreasonable adverse impacts.

5.0 RECONSTRUCTION

Comment:

Several commenters (IV-D-4, IV-D-14, IV-D-15, and IV-D-21) wrote that reconstruction costs should not be accumulated. Some commenters suggested that costs should be considered over a 1-year period.

Response:

Since in enacting Section 111 Congress did not define the term "construction," the question arose whether NSPS would apply to facilities being rebuilt. Noncoverage of such facilities would have produced the incongruity that NSPS would apply to completely new facilities, but not to facilities that were essentially new because they had undergone reconstruction of much of their component equipment. This would have undermined Congress's intent under Section 111 to require strict control of emissions as the Nation's industrial base is replaced.

EPA promulgated the reconstruction provisions in 1975, after notice and opportunity for public comment (40 FR 58420, December 16, 1975), to fulfill this intent of Congress. Since this turnover in the industrial base may occur independently of whether emissions from the rebuilt sources have increased, the reconstruction provisions do not focus on whether the changes that render a source essentially new also result in increased emissions.

Congress did not attempt to overrule EPA's previous promulgation of Section 60.15 in passing the Clean Air Act Amendments in 1977. This indicates that Congress viewed the reconstruction provisions' focus on component replacement, rather than emissions level, as consistent with Section 111. See, e.g., Red Lion Broadcasting Co. v. FCC, 395 U.S. 367 (1969); NLRB v. Bell Aerospace Division, 416 U.S. 267 (1974). Nor has any Court questioned the Agency's authority to subject reconstructed sources to new source performance standards. In fact, in ASARCO v. EPA, 578 F. 2d 319, 328 n.31 (D.C. Cir. 1978), the D.C. Circuit suggested that the reconstruction provisions may not go far enough toward preventing possible abuses by owners seeking to avoid NSPS by perpetuating the useful lives of their existing facilities indefinitely.

Finally, coverage under §60.15 of establishing petroleum refinery facilities comports well with the intent underlying Section 111. In such cases, the refurbishment may transform the existing facility into an essentially new facility. A key goal of Section 111 is to enhance air quality over the long term and minimize the potential for long-term growth by minimizing emissions through application of the best demonstrated technology to new emission sources, concurrent with the turnover of the Nation's industrial base. If owners are permitted to replace most of the equipment in their existing facilities without applying the best demonstrated technology, they will be installing new equipment without minimizing emissions and maximizing the potential for long-term industrial growth, as Congress sought in enacting Section 111. For this reason, NSPS coverage of facilities that undergo substantial component replacement through conversion accords with Section 111, even where some decrease in emissions results from the conversion.

EPA promulgated the reconstruction provisions because failure to require best control at sources that have become essentially new through extensive component replacement would have undermined Congress's intent that best technology be applied as the Nation's industrial base is replaced. Failure to cover facilities that have undergone extensive component replacement over a long period of time similarly postpones the enhancement of air quality Congress sought under Section 111. The D.C. Circuit recognized this when it expressed concern in the ASARCo case that, absent a provision for aggregating replacement expenditures "over the years," owners could evade the reconstruction provisions by continually replacing obsolete or worn-out equipment. 578 F.2d 319, 328 n.31 (D.C. cir. 1978).

Section 60.15 currently defines "reconstruction" as the replacement of components of an existing facility to such an extent that "the fixed capital cost of the new components" exceeds 50 percent of the "fixed capital cost" that would be required to construct a comparable entirely new facility and EPA determines that it is technologically and economically feasible to meet the applicable NSPS. Subsection (d) indicates that the "new components" whose cost would be counted toward the 50 percent threshold include those components the owner "proposes to replace." It is unclear under this wording whether a reconstruction has occurred in the case of an owner who first seeks to replace components of an existing facility at a cost equal to 30 percent of the cost of an entirely new facility and then, shortly after commencing or completing those replacements, seeks to replace an additional 30 percent. Specifically, it is uncertain whether the owner should be deemed to have made two distinct "proposals," or instead a single proposal.

For example, assume that a refinery owner refurbishes part of a facility and six months later refurbishes other parts of the facility. If the two actions were interpreted as separate "proposals" under Section 60.15, neither might exceed the 50 percent replacement cost threshold. Under this general interpretation, owners could avoid NSPS coverage under Section 60.15 simply by characterizing their replacement projects as distinct "proposals," even where the component replacement is completed within a relatively short period of time.

EPA did not intend, in promulgating the reconstruction provisions, that the term "propose" exclude from NSPS coverage facilities undergoing extensive component replacement. Failure to cover these sources serves to undermine Congress's intent that air quality be enhanced over the long term by applying best demonstrated technology with the turnover in the Nation's industrial base.

To eliminate the ambiguity in the current wording of Section 60.15 and further the intent underlying Section 111, the Agency is clarifying the meaning of "proposed" component replacements in Section 60.15. Specifically, the Agency is interpreting "proposed" replacement components under Section 60.15 to include components which are replaced pursuant to all continuous programs of component replacement which commence (but are not necessarily completed) within the period of time determined by the Agency to be appropriate for the individual NSPS involved. The Agency is selecting a 2-year period as the appropriate period for purposes of the petroleum refinery equipment leak NSPS (Subpart GGG). Thus, the Agency will count toward the 50 percent reconstruction threshold the "fixed capital cost" of all depreciable components (except those described above) replaced pursuant to all continuous programs of reconstruction which commence within any 2-year period following proposal of these standards. In the Administrator's judgment, the 2-year period provides a reasonable, objective method of determining whether an owner of one of these facilities is actually "proposing" extensive component replacement, within the Agency's original intent in promulgating Section 60.15.

EPA realizes that the petroluem refinery industry is constantly changing; however, the Agency believes that this 2-year limit will assure that the owner would have to make a substantial change to the facility to reach the 50 percent threshold.

The administrative effort to keep the required records should not be a burden on industry. The recordkeeping required under a cumulative basis interpretation of reconstruction is the same as the recordkeeping that would be required under a strictly project-by-project basis interpretation. In either case, the dollar amount of the component replacement taking place at the affected facility must be determined and recorded. Once this dollar amount has been determined for each change and conversion, the additional requirement of keeping this information on file at the refinery does not appear to be an excessive burden.

Comment:

Two commenters (IV-D-8 and IV-D-14) requested EPA to exclude from the reconstruction provisions the costs of equipment replacement done for routine maintenance purposes. Similarly, commenters (IV-D-4 and IV-D-15) expressed concern with the reconstruction provisions as they apply to process unit turnarounds. Commenters stated that process unit turnarounds are maintenance procedures performed to assure efficient and safe operation and, therefore, turnaround replacements should be excluded from reconstruction provisions. Another commenter (IV-D-4) requested that replacements of equipment due to fire, explosions, or other accidental causes should be exempt from reconstruction.

Response:

As discussed above, reconstruction costs are the fixed capital cost or the capital needed to provide all the "depreciable" components, while most routine maintenance practices involve the use of non depreciable components.

Because routine maintenance items (valve packings, pump seals, replacement rupture disks, nuts and bolts) cost very little compared to the cost of equipment (covered by the standards) in a process unit, it is very unlikely that routine maintenance would trigger a reconstruction even if accumulated over several years. The cost of these items is relatively small. In EPA's judgment, maintaining records of the repair or replacement of these items may constitute an unnecessary burden. Moreover, EPA does not consider the replacement of these items an element of the turnover in the life of the facility. Therefore, in accordance with 40 CFR 60.15(g), the final standards (Subpart GGG) will exempt certain frequently replaced components from consideration in applying the reconstruction provisions to petroleum refinery process unit facilities.

The costs of these frequently replaced valve parts will not be considered in calculating either the "fixed capital cost of the new components" or the "fixed capital cost that would be required to construct a comparable, entirely new facility" under Section 60.15. In EPA's judgment, these items are pump seals, valve packings, nuts and bolts, and rupture disks. Replacements of pumps, valves, and other fugitive equipment at turnarounds or at other times are included in reconstruction costs. For turnarounds that involve significant refurbishment of a process unit, EPA would likely consider this a reconstruction. EPA also considers it appropriate to include in reconstruction costs the replacement of equipment due to the accidental loss of an original component, since the reason for an owner's refurbishing a facility has no bearing on whether the facility itself is comparable to a new source for which application of the best control systems is reasonable.

Comment:

One of the commenters (IV-D-14) requested that the reconstruction provisions not apply at all, or only when the number of replacement valves exceeds 50 percent of the number of existing valves. The commenter reasoned that there is an economic justification for requiring compliance with NSPS if, for example, reactors, towers, or heaters are replaced, but not fugitive emission sources.

Response:

The standards apply to fugitive emission sources only. EPA considers it appropriate to cover process units that are essentially new. The costs considered are only those associated with the equipment covered by the standards. The commenter offered no support for his statement that the standards are not economically justified when applied to fugitive emission sources only. EPA considers the standards to reflect BDT (considering costs) for sources that become affected through reconstruction or modification. In response to the commenter's preference that the affected facility include valves only, EPA does not disagree with the concept of using the number of components as the basis for reconstruction. However, since there are several types of components covered by the standards, this approach would ignore replacements of other key portions of the facility. Thus, EPA will use the cost of replacements for all the equipment covered by the standards to determine when a reconstruction has occurred.

6.0 LEGAL

Comment:

One commenter (IV-D-21) requested that facilities commencing modification or reconstruction should be subject to compliance on the date of final promulgation rather than January 4, 1983, the date of proposal.

Response:

Under Section 111(a)(2) of the Clean Air Act, a "new source" subject to applicable standards is defined to be any source on which construction or modification commenced after the date on which the standards were proposed. The standards for equipment leaks of VOC within petroleum refineries were proposed on January 4, 1983. A group of process unit equipment (specified in the standards) or a compressor on which construction or modification commenced after that date is, therefore, a new source under the Act and subject to the standards. The commenters suggest that EPA change the applicability date to the date on which EPA promulgates the standards. Changing the applicability date of the standards would be inconsistent with the plain language of the Clean Air Act.

Comment:

Two commenters (IV-D-21 and IV-D-22) argued that the proposed standards are unnecessary because hydrocarbons generally do not affect human health as reflected in the EPA's rescinding of the national ambient air quality standards (NAAQS) for hydrocarbons (HC), and because there is no consistent quantitative relationship between the concentration of ambient air ozone and hydrocarbons. Commenters added that there is no need to regulate VOC in attainment areas.

Response:

The revocation notice for the NAAQS for HC does not directly affect the development of this NSPS. As explained in the revocation notice, the NAAQS for HC were intended only as guides in the development of State implementation plans (SIP) to attain the original NAAQS for photochemical oxidants (recast as NAAQS for ozone in 1979). EPA revoked the NAAQS for HC because EPA determined that there is no single, universally applicable relationship between HC and ozone and that HC as a class apparently do not produce any adverse health or welfare effects at concentrations at or near ambient levels. However, the revocation was in no way intended to restrict EPA or State authority to limit VOC emissions (including HC as a class) where necessary to limit the formation of ozone. Since VOC are precursors to ozone, and ozone has been determined to be harmful to public health and welfare, significant sources of VOC are subject to regulation under Section 111 of the Clean Air Act (46 FR 25656; May 9, 1981).

EPA clearly documented the need to regulate VOC in order to protect public health and welfare in the EPA publication "Air Quality Criteria for Ozone and Other Photochemical Oxidants" (Docket No. IV-A-1). VOC emissions are precursors to the formation of ozone and other oxidants (ozone). Ozone results in a variety of adverse impacts on health and welfare, including impaired respiratory function, eye irritation, necrosis of plant tissues, and the deterioration of synthetic rubber.

In setting new source performance standards, location of the industry in attainment or nonattainment areas is not relevant. Location of an industry in an attainment or nonattainment area is relevant to achieving the NAAQS under Sections 109 and 110 of the Clean Air Act. The intent of Congress in establishing NSPS was to establish a single level of stringency for all State limits, thereby preventing States from soliciting industry with lenient air pollution requirements and causing increased air pollution from new sources. The standards will limit VOC emissions from newly constructed, modified, and reconstructed refinery process units and will result in emission reductions well into the future. Even though these reductions may not bear directly now on attainment or nonattainment of NAAQS for ozone, they will make room for future industrial growth while preventing future air quality problems. Clearly, residents in both attainment and nonattainment areas would benefit from these standards. The NSPS complements the ambient air quality-based rules as a means of achieving and maintaining the NAAQS, while on a broader basis it prevents new sources from making air pollution problems worse regardless of the existing quality of ambient air. Therefore, while new source standards may help in the attainment of NAAQS, the consideration of attainment or nonattainment of the NAAQS does not influence directly the decision to set standards of performance.

Comment:

The same commenters (IV-D-21 and IV-D-22) stated that the standards would place an unreasonable burden upon the industry. The standards should be considered a major rule and not be exempt from provisions of Executive Order 12291.

Response:

Executive Order 12291 requires that a regulatory impact analysis, thoroughly examining costs and benefits of a rule, be prepared in connection with every major rule. A major rule is any regulation which is likely to result in:

(1) An annual effect on the economy of $100 million or more;

(2) A major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions; or

(3) Significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of United States-based enterprises to compete with foreign-based enterprises in domestic or export markets.

An economic analysis of these standards was prepared. Economic impact estimates presented in the background information document for the proposed standards, and summarized in the preamble to the proposed regulation (48 FR 279; January 4, 1983), showed that no unreasonable economic impacts are expected. Because no unreasonable economic impacts are expected and none of the criteria for a major rule has been met, no additional regulatory impact analysis has been prepared.

Comment:

One commenter (IV-D-21) further stated that EPA acknowledged that no new major refineries are likely to be constructed in the U.S. in the coming decade and, thus, all the emission reductions quantified in the background information document would occur at existing refineries.

Response:

Projections of units affected by new source performance standards are discussed in Appendix E of the BID for the proposed standards. EPA projected that up to 100 new units and 182 modifications/reconstructions of existing process units will be subject to the standards. EPA recognizes that few, if any, grass root refineries will be built. However, EPA also recognizes that it is appropriate to cover the industry as it rebuilds through modification and reconstruction and through the addition of new processing units at existing refineries.

7.0 TEST METHODS

Comment:

One commenter (IV-D-4) requested that EPA propose the entire rulemaking, including appropriate reference methods, at one time. The commenter said that the "failure to provide either Reference Method 21 or Reference Method 22 as appendices to these proposed rules prevents an accurate analysis of the impact of the proposed rulemaking." The application of Reference Method 22 to refinery flares was questioned.

Response:

EPA proposed Reference Method 21 on January 5, 1981, as an appendix to the proposed standards of performance for fugitive VOC emission sources in the synthetic organic chemicals manufacturing industry (SOCMI). EPA generally proposes reference methods in conjunction with the first standards that use the method. Method 21 would normally have been promulgated with the SOCMI standards. However, after reviewing the comments and incorporating changes, it was decided to promulgate Method 21 before promulgation of the SOCMI NSPS because several additional regulations were scheduled for promulgation in the near future that specified the use of Method 21. EPA considered the comments received during the comment period for the proposed refinery fugitive standards and decided that no additional changes to Method 21 were needed. Method 21 was promulgated on August 18, 1983 (48 FR 37598).

Reference Method 22 was initially promulgated on August 6, 1982. In the January 4, 1983, preamble to the proposed petroleum refinery standards, EPA stated that revisions to Method 22 would be published soon in the Federal Register to broaden its applicability to flares. This method was revised on October 18, 1983, in the rulemaking on SOCMI.

Comment:

Two commenters (IV-D-4 and IV-D-15) requested that EPA clarify the use of hexane or methane in calibrating the portable analyzer. It was suggested that a correction factor be provided to put all measurements on a consistent basis using hexane as the primary standard. The use of an uncorrected methane calibration would result in a higher number of leaking components being detected.

Response:

The basis for selection of the calibration gases for the analyzer was evaluated before proposal. It was recognized that there are a number of potential process stream components and compositions that can be expected. Since all analyzer types do not respond equally to different compounds, it was necessary to establish a reference calibration material. Based on the expected compounds and the information available on instrument response factors, hexane was chosen initially (see Control of Volatile Organic Compound Leaks from Petroleum Refinery Equipment, EPA-450/2-78-036, Document No. II-A-6) as the reference calibration gas for EPA test programs. At that time, the measurement distance was 5 centimeters (cm), and calibrations using hexane were conducted at approximately 100 or 1,000 ppm levels. After initial equipment leak data were collected at 5 cm, problems were identified with the reproducibility of results at this distance, as discussed in Appendix D of the BID for the proposed standards. The monitoring procedure was revised so that measurements were made at the surface of the interface, or essentially 0 cm. This change was accompanied by a change in the leak definition to 10,000 ppm. At this concentration hexane calibration standards were not readily available commercially. Also based on a review of the data, it appeared that methane was a more representative reference calibration material at 10,000 ppm levels. Based on this conclusion, and the fact that methane calibration standards are readily available at the necessary calibration concentrations, methane was added as an acceptable calibration gas.

Since then, studies have been completed that measured the response factors for several instrument types. The results of these studies show that the response factors for methane and hexane are similar enough for the purposes of this method for these two gases to be used as calibrants interchangeably. Therefore, the accepted calibration materials remain as hexane and methane. In response to the commenters, EPA will likely use methane as the calibration gas. Because EPA does not consider the difference in the number of leaks found using either calibration gas to be substantially different, a correlation factor to put all measurements on a consistent basis was not provided.

Comment:

One commenter (IV-D-22) warned that when used at a concentration of 10,000 ppm, hexane could condense on the walls of the container, resulting in distorted calibration results. Also, since the lower explosive limit for hexane is 12,000 ppm, calibrating with hexane could be a safety hazard.

Response:

There are a number of difficulties with using hexane as a calibrant. Based on EPA's experience, methane is the preferred calibrant. The use of hexane may lead to operators finding more leaks during monitoring because, if hexane condenses on the walls of the container storing the instrument calibration gas, the concentration of the gas may fall below 10,000 ppm. In this instance, an instrument would signal that a leak has occurred although the actual concentration is below 10,000 ppm. The fact that 10,000 ppm as hexane is close to 12,000 ppm (lower explosive limit of hexane) can be added to the factors that led EPA to require the instrument to be intrinsically safe for operation in explosive atmospheres.

Comment:

Two commenters (IV-D-6 and IV-D-12) remarked on the reasonableness of the instrument calibration requirements. It was argued that the "zero" calibration could be performed adequately with ambient air. Also, daily instrument calibration was deemed too burdensome and it was felt that weekly calibration should suffice.

Response:

The specification of air (less than 10 ppm hydrocarbon) as the zero air calibrant was intended to allow the use of relatively clean ambient air. Method 21 now specifies 10 ppm, whereas it specified 3 ppm when the standards were proposed. The use of air with less than 10 ppm hydrocarbon does allow calibration of the instrument at essentially zero reading. This is particularly important for "no detectable emission" requirements and to ensure that the monitor is functioning properly. Zero air calibrants can be purchased or generated easily (e.g., carbon filtered drawn air). Thus, there is no need to change the standards to require the zero air calibrant as ambient air only. There may be occasions when the ambient air within a refinery could have a significant VOC (organics) concentration, and calibrating with that ambient air would be inappropriate.

Instrument calibration is required on each day of its use. This is not burdensome. The procedure is relatively simple, does not require a laboratory, and takes only 15 to 30 minutes. The cost of calibrating the instrument on a daily basis was included in the cost of leak detection and repair programs. Moreover, the proper use and calibration of the monitor is vital to effective leak detection and repair. A semiannual performance evaluation of the instrument is also required by Method 21. EPA has no reason to believe that weekly calibration would provide sufficiently stable readings from the monitor. EPA's experience indicates that daily calibrations are sufficient, and that less frequent calibrations may not be adequate. Thus, no change in instrument calibration requirements was made.

Comment:

One commenter (IV-D-22) noted that proposed Reference Method 21 refers to monitoring techniques which do not distinguish between VOC and non-VOC hydrocarbons. This may result in a component having a monitor reading greater than 10,000 ppm while actual VOC emissions would be less.

Response:

The commenter is correct that Method 21 responds to non-reactive organic compounds (e.g., methane). However, the monitor reading is not intended to be a quantitative measure of the reactive organic compounds (VOC) in the leak. Its purpose is rather to indicate whether a leak exists of sufficient magnitude to warrant remedial action. EPA is using the "in VOC service" definition to exclude equipment that would not contain enough reactive organic compounds to warrant coverage by the standards. Thus, if a piece of equipment is in VOC service and a leak of 10,000 ppm is detected, EPA judges that repair is warranted. For this reason, correcting the 10,000 ppm leak definition to "VOC only" is unnecessary.

Comment:

A commenter (IV-D-22) suggested that there was inconsistency in EPA's decision not to allow leak detection using a soap solution because the magnitude of leak rates is difficult to assess, yet the VOC monitoring instrument "would yield qualitative indications of leaks."

Response:

Since proposal, an alternative screening procedure has been added to Method 21 for those sources that can be tested with a soap solution. These sources are restricted to those with non-moving seals, moderate surface temperatures, without large openings to atmosphere, and without evidence of liquid leakage. The soap solution is sprayed on all applicable sources and the potential leak sites are observed to determine if bubbles are formed. If no bubbles are formed, then no detectable emissions or leak exists. If any bubbles are formed, then the instrument measurement techniques must be used to determine whether a leak exists, as defined in the regulation.

The alternative soap solution procedure does not apply to pump seals, components with surface temperatures greater than the boiling point or less than the freezing point of the soap solution, components such as open-ended lines or valves, pressure relief valve horns, vents with large openings to atmosphere, or any component where liquid leakage is present. The instrument technique specified in the method must be used for these components.

The alternative of establishing a soap scoring leak definition equivalent to a concentration based leak definition is not included in the method and is not recommended for inclusion in an applicable regulation because of the difficulty of calibrating and normalizing a scoring technique based on bubble formation rates. A scoring technique would be based on estimated ranges of volumetric leak rates. These estimates depend on the bubble size and formation rate, which are subjective judgments of an observer. These subjective judgments could be calibrated or normalized only by requiring that the observers correctly identify and score a standard series of test bubbles. It has been reported that trained observers can correctly and repeatedly classify ranges of volumetric leak rates. However, because soap scoring requires subjective observations and since an objective concentration measurement procedure is available, a soap scoring equivalent leak definition is not recommended for the applicable regulation. The alternative procedure that has been included will allow more rapid identification of potential leaks for more rigorous concentration measurement using a monitoring instrument.

Comment:

A commenter (IV-D-8) argued that it is unreasonable to require annual monitoring of "entire vent or control systems." These piping systems are typically operated at low pressure (which minimizes the amount of potential leakage) and are routed overhead in pipe racks and are, therefore, inaccessible.

Response:

Method 21 is used to monitor closed vent systems used in complying with the standards. Method 21 requires the use of an organic compound monitor only where leaks might occur. Where no leaks can occur (like header-pipes), Method 21 requires only a visual inspection to ensure the closed vent system has not deteriorated and is not leaking where leaks are not expected.

Closed vent systems used to comply may be operated at low pressure or high pressure. Either type of system may leak at connections and, therefore, the annual test is appropriate. If an owner or operator uses an approach of ensuring a leak-free system, such as monitoring oxygen in a vacuum system, EPA will consider whether this approach can be used rather than Method 21, as specified in §60.13(i) of the General Provisions. Like other sources that are difficult-to-monitor, annual monitoring, if needed, in a pipe rack is not unreasonable in light of the emissions that would occur from such a leak.

8.0 RECORDKEEPING AND REPORTING

Comment:

A number of commenters (IV-D-8, IV-D-12, IV-D-21, and IV-D-22) wrote that the proposed recordkeeping requirements are needlessly complex and burdensome. One commenter (IV-D-22) estimated that the additional paperwork burden would amount to 2 person-months per year per affected refinery. Two commenters (IV-D-8 and IV-D-12) listed specific recordkeeping requirements that should be deleted. These requirements include records of: (1) identification numbers for instruments, operators, fugitive emission components, leaking components, components in vacuum service, and components designated as difficult-to-monitor or unsafe-to-monitor; (2) repair methods; (3) logging shutdown and startup for closed vent systems; (4) signature of owner or operator (or designee) whose decision it was that repair could not be effected without a process shutdown; (5) expected date of repair; (6) explanation for unsafe or difficult-to-monitor designation; and (7) schematics, design specifications, and operations records on flares used as control devices.

Response:

Before the standards were proposed, EPA considered three alternative levels of recordkeeping. The proposed recordkeeping requirements are considered the minimum consistent with adequate enforcement; thus, the paperwork burden on owners and operators is the minimum amount necessary to enforce the standards adequately. At proposal, EPA weighed the paperwork burden against the enforcement authority (Federal, State and local) to determine compliance with the standards and selected the proposed requirements.

Compliance with the final standards will be generally determined through inspection. However, because the intent of the standards is a continuous reduction in equipment leaks of VOC and continuous inspection by enforcement authorities is not possible, records must be maintained if an inspector is to determine retrospectively whether a facility is in compliance with the standards. EPA considers the required records for an owner or operator's leak detection and repair program necessary to document the operator's compliance efforts. These records would likely be maintained by a prudent owner or operator, and should therefore add little additional recordkeeping burden.

Commenters did not explain why specific records would not be needed by enforcement authorities. EPA considers the required records for an owner or operator's leak detection and repair program necessary to document the operator's compliance efforts. For example, when an unsuccessful repair attempt is made, a record of the attempted or anticipated methods of repair shows what effort was made by the operator and the reason for delay. Without such records, EPA and other enforcement authorities would not be able to determine compliance with the standards. Additionally, an expected repair date is obviously required in such cases to prevent a known leak from being allowed to persist. Records, such as identification numbers for components in vacuum service, can be used to check compliance with the standards. The same reasons are applicable to records for operation of control devices. Obviously, a control device (including flares) serves no function when not operating. As such, demonstration of shutdown or flame-out periods is necessary to show compliance. These records would likely already be maintained by a prudent owner or operator, and should therefore add little additional recordkeeping burden.

The records required for identifying fugitive emission components, and control device schematics and design data are not unreasonably burdensome. This information would be developed only once, and would require changing or updating only if the facility were changed. The control device schematics and design data should be available to plant engineers already, and as such do not represent an added burden. For new facilities, the reasons why a component must be installed in a location which makes it difficult or unsafe to monitor must be documented prior to installing the component in such a position. The number of difficult-to-monitor or unsafe-to-monitor components will be small and, therefore, should not create an excessive recordkeeping burden. After considering the comments that the recordkeeping requirements are needlessly complex and burdensome, EPA decided to promulgate the recordkeeping requirements as proposed.

Comment:

One commenter (IV-D-22) complained that the demonstration required for a variance from the 15-day repair requirement is a recordkeeping nightmare due to the many different types and sizes of valves.

Response:

The proposed standards permit delay of repair beyond the 15-day period as provided in Section 60.592-9. The provisions for delay for repair are automatic, and not a variance (as the commenter implied) that must be applied for as suggested by the commenter. EPA recognizes that some repairs cannot be performed on line, and that not all components can be isolated without a process unit shutdown. These repairs should be readily understood by the operator. Therefore, a relatively straightforward response (e.g., the seal must be replaced at a shutdown--pump cannot be bypassed; there is no spare) sufficiently informs EPA why repair is delayed for a particular component and, accordingly, can be used to determine whether compliance with the standards has been maintained. The intent of the recordkeeping provision is to ensure that all technically feasible repairs are performed within 15 days.

Comment:

A commenter (IV-D-14) wrote that the actual cost for a leak detection and repair program as required by the standards would be higher than EPA estimated because daily recordkeeping of components replaced frequently is not included, nor are the associated costs necessary to determine when a process unit becomes an affected facility.

Response:

The recordkeeping associated with frequent replacements and evaluating changes in operation would be something a plant would typically do on its own for purposes other than complying with the standards (e.g., tracking the cost of production or assuring that adequate spare parts or components are stocked). A small additional increase might be experienced by the owner as a result of these standards. However, the entire cost of recordkeeping should not be attributed to the standards as indicated by the commenter. The exclusion of certain routine replacement items from reconstruction calculations (see Section 5) and the addition of alternative methods for determining capital expenditure (see Section 4) eases the recordkeeping needs. The cost of pre-construction efforts, pre-modification efforts, or pre-reconstruction efforts are not accounted for explicitly in the impacts of the standards because they are considered part of the overall cost of the owner's decision to construct, modify, or reconstruct. As such, it would be very difficult to make reasonable estimates of the cost to determine when a process unit becomes an affected facility. But, EPA believes that those costs are insignificant in comparison to the costs associated with other activities that occur during these efforts. In any cases, these costs would not raise the overall cost effectiveness ($130/Mg) to an unreasonable level.

Comment:

Two commenters (IV-D-30 and IV-D-22) remarked that the standards are not enforceable. As a result one of the commenters (IV-D-22) concluded that those facilities not following the NSPS would have a competitive advantage of reduced cost over those facilities complying with the regulations. Additionally, the other commenter (IV-D-30) strongly opposed the proposal of no reporting requirements which, the commenter noted, undermines the effectiveness of the standards and the ability of EPA and the States to enforce them. Reporting requirements, according to the commenter, would enhance self-enforcement. The commenter speculated that the reason for EPA's excluding reporting requirements was OMB's role in administering the Paperwork Reduction Act, which, the commenter asserted, does not give OMB or EPA the authority to compromise the effectiveness of the standards. The commenter was also concerned that no records are required for equipment not found to be leaking, adding that a much better incentive to comply with the regulation would exist if records were required to be kept on all monitored equipment.

Response:

Reports, records, and inspections will be used to ensure compliance by all facilities subject to these standards. State and EPA Regional air quality control authorities have successfully implemented regulations similar to the standards. At proposal EPA stated that routine reporting was not required. Reporting requirements were limited to notifications of construction, anticipated startup and actual startup, and an intention to comply with one of the alternative standards. As stated in the preamble for the proposed standards, these reporting requirements would not provide a mechanism for checking the thoroughness of the industry's efforts to reduce fugitive emissions of VOC. As stated in the preamble to the proposed standards, compliance would be assessed through in-plant inspections.

EPA has decided that reporting is necessary to assess implementation of the work practice and equipment requirements of the standards. EPA agrees with the commenter that facilities not complying with the standards might have an unfair advantage (albeit, somewhat small). More importantly, facilities not complying with the standards would not be using BDT as required by the Clean Air Act, the purpose of which is to prevent new air pollution problems. EPA believes that reporting is necessary for the effective enforcement of the standards. Reporting will reduce the necessity for many in-plant inspections, while improving the enforceability of the standards. EPA's conclusion that reports are useful is also based on the experience of the State and local air quality control boards.

As explained at proposal, three alternatives were considered for reporting requirements. The three alternatives represented trade-offs among varying amounts of in-plant inspections and report preparation for enforcement. The first alternative required minimal reporting and relied on inspections for enforcement. The third alternative relied almost totally on reports and would require minimum inspections to judge compliance. The second alternative represented a compromise with some reporting and some inspections required and is included in the final regulations. These reporting requirements, however, have been streamlined to include reporting of data on leak detection and repair of pumps, valves, and other equipment types only. In addition, periodic reports are on a semiannual rather than quarterly basis, and the requirement for certification of reports has been eliminated. The semiannual reporting requirements may be waived for affected sources in any State that is delegated authority to enforce these standards, provided EPA approves reporting requirements or an alternative means of source surveillance adopted by the State. Such sources would be required to comply with the requirements adopted by the State.

The following reporting requirements were added to the standards since proposal:

Each owner or operator must submit semiannual reports beginning 6 months after the initial startup date. The initial semiannual report includes:

(1) Process unit identification,

(2) Number of valves subject to the requirements excluding those valves designated for no detectable emissions,

(3) Number of pumps subject to the requirements excluding those pumps designated for no detectable emissions and those pumps enclosed and vented to a control device, and

(4) Number of compressors subject to the requirements excluding those compressors designated for no detectable emissions and those compressors enclosed and vented to a control device.

All subsequent semiannual reports must include:

(1) Process unit identification, and

(2) For each month during the semiannual reporting period, the number of valves, pumps, and compressors for which leaks were detected and the number of valves, pumps, and compressors for which leaks were not reported.

The semiannual reports will present the facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible. In addition, the semiannual reports will give dates of process unit shutdowns which occurred within the semiannual reporting period, and revisions to items reported according to paragraph (b) if changes have occurred since the initial report or subsequent revisions to the initial report.

The Paperwork Reduction Act of 1980 (PL-511) requires clearance from the Office of Management and Budget (OMB) of reporting and recordkeeping requirements that qualify as an "information collection request" (ICR). For the purposes of OMB's review, an analysis of the burden associated with the reporting and recordkeeping requirements of this regulation has been made. During the years 1984 and 1985, the average annual burden of the reporting and recordkeeping requirements of this regulation to industry would be about 20 person-years.

APPENDIX A

INCREMENTAL COST EFFECTIVENESS OF CONTROL TECHNIQUES FOR EQUIPMENT LEAKS OF VOC

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INCREMENTAL COST EFFECTIVENESS OF CONTROL TECHNIQUES FOR EQUIPMENT LEAKS OF VOC

Table A-1 summarizes the individual component control impacts and the incremental cost effectiveness for each individual component and control technique. The individual component control impacts are derived in Tables A-2 through A-13. The net annualized cost, emission reduction, cost effectiveness, and incremental cost effectiveness of the control techniques are discussed in Chapter 2.0.

Table A-1. SUMMARY OF THE INDIVIDUAL COMPONENT CONTROL IMPACTS[a]

Fugitive Emission Source	Control Technique	Emission Reduction (Mg/yr)	Average Cost Effectiveness[b] ($/Mg)	Incremental Cost Effectiveness[c] ($/Mg)
Pressure relief devices	Quarterly LDR	4.4	(170)	(170)
	Monthly LDR	5.3	(110)	250
	Rupture disks[d]	9.8	410	1,000
Compressors	Controlled degassing vents	16.5	150	150
Open-ended valves	Caps on open ends	2.8	460	460
Sampling connection systems	Closed purge sampling	2.6	810	810
Valves	Quarterly LDR	66	(110)	(110)
	Monthly LDR	77	(60)	310
	Sealed bellows valves	110	4,700	16,700
Pumps	Annual LDR	3.0	860	860
	Quarterly LDR	9.8	157	(140)
	Monthly LDR	11.5	158	170
	Dual mechanical seal system	13.9	2,000	10,900

(xx) = Cost savings
LDR = Leak detection and repair.

[a] Costs and emission reductions are based on fugitive emission component counts in Model B from the BID for the proposed standards, EPA-450/3-81-015a, page 6-3, and from Tables A-2 through A-13 of this appendix.

[b] Average Cost Effectiveness = net annualized costs per component ÷ annual VOC emission reduction per component.

[c] Incremental Cost Effectiveness = (net annualized cost of the control technique - net annualized cost of the next less restrictive control technique) ÷ (annual emission reduction of control technique - annual emission reduction of the next less restrictive control technique).

[d] Underlined control techniques were selected as basis for standards.

Table A-2. PRESSURE RELIEF DEVICE IMPACTS (May 1980 dollars)

Per Pressure Relief Device Item/Control Technique	Quarterly LDR	Monthly LDR	Rupture Disks
Installed Capital Cost	0[a]	0[a]	3,100[b]
Annualized Capital Costs[c]			
A. Control Equipment	--[a]	--[a]	600
B. Initial Leak Repair[d]	0	0	0
Annualized Operating Costs			
A. Maintenance[e]	--[a]	--[a]	160
B. Miscellaneous[f]	--[a]	--[a]	120
1. Monitoring[g]	19	58	0
2. Leak Repair[d]	0	0	0
3. Administrative and Support[h]	7.6	23	0
Total Annual Costs Before Credit	27	81	880
Recovery Credit[i]	135	161	300
Net Annualized Costs[j]	(110)	(80)	580
Total VOC Emission Reduction (Mg/yr)[k]	0.63	0.75	1.4
Cost Effectiveness ($/Mg VOC)[l]	(170)	(110)	410
Incremental Cost Effectiveness[m] ($/Mg VOC)	(170)	250	1,000

(XX) = Cost Savings
(LDR) = Leak Detection and Repair

Model Unit B: 7 pressure relief valves
Emission Reductions
Quarterly LDR = 7 x 0.63 Mg/yr = 4.4 Mg/yr
Monthly LDR = 7 x 0.75 Mg/yr = 5.3 Mg/yr
Rupture Disks = 7 x 1.4 Mg/yr = 9.8 Mg/yr

Table A-2. PRESSURE RELIEF DEVICE IMPACTS
(May 1980 dollars)
(Continued)

[a] Cost of monitoring instrument is not included in this analysis.

[b] Capital cost for rupture disk is from BID for proposed standards Table 8-1.

[c] Obtained by multiplying capital recovery factor (2 years, 10 percent interest = 0.58) by capital cost for rupture disk and capital recovery factor (10 years, 10 percent interest = 0.163) by capital cost for all other equipment (rupture disk holder, piping, valves, pressure relief valve). Based on new installation cost 0.163 (3100 - 230) + 0.58 (230) = 600.

[d] Leaks are corrected by routine maintenance in the absence of the standards; therefore, no cost is incurred for repair.

[e] 0.05 x capital cost. From BID for proposed standards, Table 8-5.

[f] 0.04 x capital cost. From BID for proposed standards, Table 8-5.

[g] Monitoring labor hours (i.e., number of workers x number of components x time to monitor x times monitored per year) x $18 per hour. Assumes 2-man monitoring team per relief valve, 8 minutes monitoring team per valve.

[h] 0.40 x (monitoring cost + leak repair cost). From BID for proposed standards, Table 8-5.

[i] Recovery credit based on uncontrolled VOC emission factor of 3.9 kg/day (BID Table 3-1) and 44 percent control efficiency for quarterly inspections (BID Table F-7), 53 percent control efficiency for monthly inspections, and 100 percent for rupture disks. Control efficiency for monthly inspections is estimated based on the method used to calculate control efficiency for quarterly inspections in Table F-7 (footnote f) of the BID for the proposed standard. [Ratio of estimated control efficiency for gas/vapor valve ABCD model (monthly inspections) to gas/vapor valve LDAR model estimate (BID Table F-3) multiplied by safety/relief valve ABCD model control effectiveness for monthly inspections (0.68) based on Table 7-1, BID for proposed standard, ABCD factors: A = 0.74, B = 0.95, C = 0.98, D = 0.98]. Therefore, control efficiency for monthly inspections = $(0.68)\,\frac{(0.703)}{(0.91)} = 0.53$

Recovered product valued at $215/Mg VOC (from BID Table 8-5).
Recovered emissions:

$$\text{Quarterly LDR} = \frac{3.9\ \text{kg}}{\text{day}} \times 0.44 \times \frac{365\ \text{days}}{\text{yr}} \times \frac{1\ \text{Mg}}{1000\ \text{kg}} = \frac{0.63\ \text{Mg}}{\text{yr-relief device}}$$

$$\text{Monthly LDR} = \frac{3.9\ \text{kg}}{\text{day}} \times 0.53 \times \frac{365\ \text{days}}{\text{yr}} \times \frac{1\ \text{Mg}}{1000\ \text{kg}} = \frac{0.75\ \text{Mg}}{\text{yr-relief device}}$$

Table A-2. PRESSURE RELIEF DEVICE IMPACTS
(May 1980 dollars)
(Concluded)

$$\text{Rupture Disk} = \frac{3.9\text{ kg}}{\text{day}} \times \frac{365\text{ days}}{\text{yr}} \times \frac{1\text{ Mg}}{1000\text{ kg}} = \frac{1.4\text{ Mg}}{\text{yr-relief device}}$$

[j] Total annual cost (before credit) minus recovery credit.

[k] Based on uncontrolled VOC emission factor and control efficiencies for each control technique in footnote i.

[l] Obtained by dividing net annualized cost by total VOC emission reduction.

[m] Incremental cost effectiveness =

$$\frac{\text{Net annualized cost of control technique} - \text{Net annualized cost of next less restrictive control}}{\text{Annual VOC emission reduction of control technique} - \text{Annual VOC emission reduction of next less restrictive control}}$$

Table A-3. COMPRESSOR SEAL IMPACTS
(May 1980 dollars)

Per Compressor Item/Control Technique	Closed Vent and Seal System
Installed Capital Cost[a]	8,000
Annualized Capital Costs Control Equipment[b]	1,300
Annualized Operating Costs	
A. Maintenance[c]	400
B. Miscellaneous[d]	320
Total Annual Costs Before Credit	2,020
Recovery Credit[e]	1,180
Net Annualized Costs[f]	840
Total VOC Emission Reduction (Mg/yr)[g]	5.5
Cost Effectiveness ($/Mg VOC)[h]	150

Model Unit B: 3 compressors

Emission Reductions:
3 x 5.5 Mg VOC/yr = 16.5 Mg/yr.

[a] Capital cost from BID for proposed standards, Table 8-1.

[b] 0.163 capital recovery factor x capital cost; from BID for proposed standards, Table 8-5.

[c] 0.05 x capital cost. From BID for proposed standards, Table 8.5.

[d] 0.04 x capital cost. From BID for proposed standards, Table 8.5.

[e] Recovery credit is based on uncontrolled VOC emission factor of 15 kg/day (BID for proposed standards, Table 3-1) and 100 percent control efficiency. Recovered product valued at $215/Mg (from BID for proposed standards, Table 8-5). Recovery credit assumes captured emissions are recycled to a process line or used for process heater fuel at a similar value.

[f] Total annual cost (before credit) minus recovery credit.

[g] Based on uncontrolled emission factor of 15 kg/day (BID Table 3-1) and 100 percent control efficiency for a closed vent and seal system:

15 kg/day x 365 days/yr x 1 Mg/1,000 kg = 5.5 Mg/yr.

[h] Obtained by dividing net annualized cost by total VOC emission reduction.

Table A-4. OPEN-ENDED LINES IMPACTS (May 1980 dollars)

Per Open-ended Line Item/Control Technique	Caps
Installed Capital Cost[a]	53
Annualized Capital Costs Control Equipment[b]	8.6
Annualized Operating Costs	
A. Maintenance[c]	2.7
B. Miscellaneous[d]	2.1
Total Annual Costs Before Credit	13.4
Recovery Credit[e]	4.3
Net Annualized Costs[f]	9.1
Total VOC Emission Reduction (Mg/yr)[g]	0.020
Cost Effectiveness ($/Mg VOC)[h]	460

Model Unit B: 140 open-ended lines.

Emission Reductions:
140 x 0.020 Mg/VOC/yr = 2.8 Mg/yr.

[a] From BID for proposed standards, Table 8-1.

[b] 0.163 (capital recovery factor) x capital cost; from BID for proposed standards, Table 8-5.

[c] 0.05 x capital cost. From BID for proposed standards, Table 8.5.

[d] 0.04 x capital cost. From BID for proposed standards, Table 8.5.

[e] Recovery credit based on uncontrolled VOC emission factor of 0.055 kg/day (from BID for proposed standards, Table 3-1). Based on 100 percent control efficiency for caps and $215/Mg VOC emission reduction (from BID for proposed standards, Table 8-5).

Emission Reduction:
0.055 kg/day/open-ended line x 365 day/yr x 1 Mg/1,000 kg = 0.020 Mg/yr

Recovery Credit:
0.020 Mg/yr x $215/Mg VOC = $4.3/yr/open-ended line.

[f] Total annual cost (before credit) minus recovery credit.

[g] Based on uncontrolled emission factor and control efficiency in footnote e.

[h] Obtained by dividing net annualized cost by total VOC emission reduction.

Table A-5. SAMPLING CONNECTION SYSTEM IMPACTS
(May 1980 dollars)

Per Sampling Connection System Item/Control Technique	Closed Purge Sampling System
Installed Capital Cost[a]	530
Annualized Capital Costs Control Equipment[b]	86
Annualized Operating Costs	
A. Maintenance[c]	26
B. Miscellaneous[d]	21
Total Annual Costs Before Credit	133
Recovery Credit[e]	28
Net Annualized Costs[f]	105
Total VOC Emission Reduction (Mg/yr)[g]	0.13
Cost Effectiveness ($/Mg VOC)[h]	810

Model Unit B: 20 sampling connections.

Emission Reductions:
20 x 0.13 Mg/VOC/yr = 2.6 Mg/yr.

[a] From BID for proposed standards, Table 8-1.

[b] Capital recovery factor (0.163) x capital cost; from BID for proposed standards, Table 8-5.

[c] 0.05 x capital cost. From BID for proposed standards, Table 8.5.

[d] 0.04 x capital cost. From BID for proposed standards, Table 8.5.

[e] Recovery credit based on uncontrolled VOC emission factor of 0.36 kg/day (from BID for proposed standards, Table 3-1). Based on 100 percent control efficiency.

Recovered Emissions:
0.36 kg/day x 365 day/yr x 1 Mg/1,000 kg = 0.13 Mg/yr

Recovery Credit:
$215/Mg x 0.13 Mg/yr = $28/yr.

[f] Total annual cost (before credit) minus recovery credit.

[g] Based on uncontrolled VOC emission factor and 100 percent control as shown in footnote e.

[h] Obtained by dividing net annualized cost by total VOC emission reduction.

Table A-6. VALVE EMISSIONS AND EMISSION REDUCTIONS

Control-Service	Emission Per Valve (kg/day)		Emission Reduction Per Valve (Mg/yr)[a]			Emission Reduction Per Model Unit B (Mg/yr)[b]		
	Gas	Light liquid	Gas	Light liquid	Weighted Average[c]	Gas	Light liquid	Total[d]
Uncontrolled	0.64	0.26	--	--	--	--	--	--
Quarterly LDR	0.262	0.098	0.14	0.059	0.087	35.9	29.6	65.5
Monthly LDR	0.192	0.072	0.16	0.069	0.10	42.5	34.3	76.8
Sealed Bellows Valves[e]	0	0	0.23	0.095	0.14	60.7	47.4	108

LDR = Leak Detection and Repair

[a] Emission Reductions Per Valve Calculated as:

$$\left(\begin{array}{c}\text{Uncontrolled emissions}\\ \text{per valve (kg/hr)}\\ \text{(from BID Table 3-1)}\end{array} - \begin{array}{c}\text{Controlled emissions}\\ \text{per valve (kg/hr)}\\ \text{(from BID Table F-7)}\end{array}\right) \times \frac{\text{365 days}}{\text{year}} \times \frac{\text{1 Mg}}{\text{1000 kg}}$$

Example Calculation: gas service, quarterly LDR = (0.64 - 0.262) x 365 ÷ 1000 = 0.14 Mg/yr

[b] Based on Model Unit B: 260 gas service valves and 500 light liquid service valves.
Example Calculation: gas service, quarterly LDR = (0.64 - 0.262) x 365 ÷ 1000 x 260 = 35.9 Mg/yr

[c] Weighted average is based on Model Unit B valve population. Weighted average is calculated by using the formula:

$$\left(\frac{260}{260+500} \times \begin{array}{c}\text{gas service}\\ \text{emission}\\ \text{reduction}\end{array}\right) + \left(\frac{500}{260+500} \times \begin{array}{c}\text{light liquid service}\\ \text{emission reduction}\end{array}\right)$$

Example calculation: quarterly LDR =

$$\left(\frac{260}{260+500} \times 0.14\text{ Mg/yr}\right) + \left(\frac{500}{260+500} \times 0.059\text{ Mg/yr}\right) = 0.087\text{ Mg/yr}$$

The emission reductions reported in the proposal preamble are on a per component basis, therefore, it is necessary to derive per valve impacts by weighting the gas and light liquid service emission reductions by their relative component counts in Model Unit B. The resulting emission reductions per valve represent a weighted average.

[d] Model Unit B emission reductions presented in the proposal preamble Table 1 represent a weighted average of the gas and light liquid emission reductions, calculated as:

Quarterly LDR

$$\left(\frac{260}{760} \times 35.9\text{ Mg/yr}\right) + \left(\frac{500}{760} \times 29.6\text{ Mg/yr}\right) = 31.7\text{ Mg/yr}$$

Monthly LDR

$$\left(\frac{260}{760} \times 42.5\text{ Mg/yr}\right) + \left(\frac{500}{760} \times 34.3\text{ Mg/yr}\right) = 37.1\text{ Mg/yr}$$

However, total emissions from gas and light liquid service valves in Model Unit B should have been reported rather than a weighted average. Individual valve weighted average impacts are used to determine the per component cost effectiveness.

[e] From BID for proposed standards, Section 4.3.3.

Table A-7. VALVE LEAK DETECTION AND REPAIR COSTS[a]
(May 1980 dollars)

Per Valve Cost Item/LDR-Service	Quarterly			Monthly		
	Gas	Light liquid	Weighted Average[b]	Gas	Light liquid	Weighted Average[b]
Initial Leak Repair[c]	0.46	0.51	0.49	0.46	0.51	0.49
Monitoring Labor[d]	2.4	2.4	2.4	7.1	7.1	7.1
Recurring Leak Repair Labor[e]	3.8	3.8	3.8	3.9	3.9	3.9
Administration and Support[f]	2.5	2.5	2.5	4.4	4.4	4.4
Total Annualized Cost	9.2	9.2	9.2	16	16	16
Product Recovery Credit[g]	(30)	(13)	(19)	(34)	(15)	(22)
Net Annualized Cost[h]	(21)	(4)	(10)	(18)	1	(6)

(XX) = Cost Savings
LDR = Leak Detection and Repair

[a] Cost of monitoring instrument is not included in this analysis.

[b] Based on Model Unit B: 260 gas service and 500 light liquid service valves.

Weighted average calculated by using the formula:

$$\left(\frac{260}{260 + 500} \times \begin{array}{c}\text{gas service}\\ \text{cost item}\end{array}\right) + \left(\frac{500}{260 + 500} \times \begin{array}{c}\text{light liquid service}\\ \text{cost item}\end{array}\right)$$

[c] From BID for proposed standards, Tables 8-3, 8-5, and 8-6. Calculated as:

Initial leak frequency x 1.13 hrs/valve x 18/hr x 1.4 x 0.163

[d] From BID for proposed standards, Tables F-4 and F-12. Calculated as:

$$\begin{array}{l}\text{Fraction of Sources Screened}\\ \text{(from BID Table F-4, 2nd}\\ \text{turnaround Annual Average)}\end{array} \times \frac{1\text{ min}}{\text{valve}} \times \frac{1\text{ hr}}{60\text{ min}} \times \frac{\$18.00}{\text{hr}} \times 2\text{ workers}$$

Example Calculation: Gas Valves, Monthly LDR = 11.8 x 1/60 x 18.00 x 2 = $7.1

[e] From BID for proposed standards, Tables F-4 and F-12. Calculated as:

$$\begin{array}{l}\text{Fraction of Sources Operated on,}\\ \text{from BID Table F-4, 2nd}\\ \text{turnaround annual average}\end{array} \times \frac{1.13\text{ hrs}}{\text{valve}} \times \frac{\$18.00}{\text{hr}}$$

Example calculation: gas service, quarterly LDR =

[(0.1762 + 0.1970)/2] x 1.13 x $18 = $3.80

[f] From BID for proposed standards, Table 8-5.
Calculated as: 0.4 x (monitoring labor + recurring leak repair labor)

[g] Calculated as: $215 x emission reductions (given in Table 6).

[h] Total annual cost (before credit) minus recovery credit.

Table A-8. SEALED BELLOWS VALVE COST IMPACTS (May 1980 dollars)

Per Valve Cost Item	
Capital Cost[a]	2,730
Annualized Cost[b]	
Capital recovery	440
Maintenance	140
Miscellaneous	110
Total annualized cost	690
Product recovery credit[c]	(30)
Net annualized cost	660

(xx) = Cost Savings

[a] From BID for proposed standards, Table 8-1.

[b] Basis for annualized costs from BID for proposed standards, Table 8-5.

[c] Calculated as: \$215 x emission reductions (given in Table 6)

Table A-9. COST EFFECTIVENESS OF VALVE CONTROLS
(May 1980 dollars)

Per Valve Item/Control	Quarterly LDR	Monthly LDR	Sealed Bellows Valves
Net Annualized Cost[a]	(10)	(6)	660
VOC Emission Reduction (Mg/yr)[b]	0.087	0.10	0.14
Cost Effectiveness ($/Mg VOC)[c]	(110)	(60)	4,700
Incremental Cost Effectiveness ($/Mg VOC)[d]	(110)	310	16,700

(xx) = Cost Savings
LDR = Leak Detection and Repair

[a] From Tables 7 and 8.

[b] From Table 6.

[c] Calculated as:

$$\frac{\text{Net annualized Costs (\$/yr)}}{\text{annual VOC emission reduction (Mg/yr)}}$$

[d] Calculated as:

$$\frac{\text{Net annualized cost of control technique} - \text{Net annualized cost of next less restrictive control}}{\text{Annual VOC emission reduction of control technique} - \text{Annual VOC emission reduction of next less restrictive control}}$$

Table A-10. PUMP EMISSIONS AND EMISSION REDUCTIONS

Control	Emissions Per Per Pump (kg/day)	Emission Reductions Per Pump (Mg/yr)[a]
Uncontrolled	2.7[b]	———
Annual LDR	2.12[c]	0.21
Quarterly LDR	0.79[c]	0.70
Monthly LDR	0.45[c]	0.82
Dual Seal System	0[d]	0.99

LDR = Leak Detection and Repair

Model Unit B = 14 pump seals in light liquid service.

Emission reductions:

Annual LDR	3.0 Mg/yr
Quarterly LDR	9.8 Mg/yr
Monthly LDR	11.5 Mg/yr
Dual Seal System	13.9 Mg/yr

[a] Calculated as:

$$\begin{array}{c}\text{Uncontrolled}\\ \text{emissions per}\\ \text{pump seal}\\ \text{(kg/hr)}\end{array} - \begin{array}{c}\text{Controlled}\\ \text{emissions per}\\ \text{pump seal}\\ \text{(kg/hr)}\end{array} \times \frac{365\text{ days}}{\text{year}} \times \frac{1\text{ Mg}}{1000\text{ kg}}$$

Example calculation: annual LDR =

$$(2.7\text{ kg/day} - 2.12\text{ kg/day}) \times 365 \div 1000 = 0.21\text{ Mg/yr}$$

[b] From BID for proposed standards, Table 3-1.

[c] From BID for proposed standards, Table F-5.

[d] From BID for proposed standards, Section 4.3.1.1.

Table A-11. PUMP LEAK DETECTION AND REPAIR COSTS (May 1980 dollars)[a]

Per Pump Seal Cost Item/Control	LDR Annual	 Quarterly	 Monthly
Initial Repair			
labor[b]	16	16	16
Replacement Seals[c]	5.5	5.5	5.5
Maintenance-ongoing			
Replacement Seals[d]	48	55	57
Monitoring Labor			
Instrument[e]	3	12	36
Visual[f]	7.8	7.8	7.8
Recurring Repair Labor[g]	98	110	120
Administration and Support[h]	44	52	66
Total Annualized Cost	220	260	310
Product Recovery Credit[i]	45	150	180
Net Annualized Cost[j]	180	110	130

(XX) = Cost Savings
LDR = Leak Detection and Repair

[a] Pump seal repair costs are based on 16 labor hours per pump repair and includes $140 per repair for a replacement seal. This analysis does not include the cost of monitoring instrument.

[b] From BID for proposed standards, Tables 8-3 and 8-5. Calculated as:

Estimated percent of initial pumps leaking (BID Table 8-3) x labor hours per seal repair x labor rate x Administration and support costs x Capital recovery factor

Example calculation: annual LDR =

(0.24) x (16) x ($18) x (1.4) x (0.163) = $16

[c] Initial replacement seal cost is calculated as:

Estimated percent of initial pumps leaking (BID Table 8-3) x $140/ replacement seal x 0.163 Capital recovery factor

[d] Ongoing replacement seal cost calculated as:

Fraction of Sources operated on (from BID Table F-6) x $140/ replacement seal

Table A-11. PUMP LEAK DETECTION AND REPAIR COSTS
(May 1980 dollars)[a]
(Concluded)

Example calculation: annual LDR =

$$(0.3397) \times (\$140) = \$48$$

[e] Calculated as:

$$\underset{\text{(from BID Table F-6)}}{\text{fraction of sources screened}} \times \frac{5\ \text{min}}{\text{pump seal}} \times \frac{1\ \text{hr}}{60\ \text{min}} \times \frac{\$18}{\text{hr}} \times 2\ \text{workers}$$

Example calculation: annual LDR =

$$(1) \times (5/60) \times (\$18) \times (2) = \$3$$

[f] Calculated as:

$$\frac{0.5\ \text{min}}{\text{pump seal}} \times \frac{52}{\text{yr}} \times \frac{1\ \text{hr}}{60\ \text{min}} \times \frac{\$18}{\text{hr}} \times 1\ \text{worker} = \$7.8$$

[g] Calculated as:

$$\underset{\text{(from BID Table F-6)}}{\text{fraction of sources operated on}} \times \text{labor hours per seal repair} \times \frac{\$18}{\text{hr}}$$

Example calculation: annual LDR =

$$(0.3397) \times (16\ \text{hrs/seal repair}) \times (\$18) = \$98$$

[h] Administration and support = 0.4 x (monitoring labor + recurring leak repair labor)

[i] Calculated as:

$$\underset{\text{(from Table 10)}}{\text{Emission Reduction}} \times \$215/\text{Mg}$$

[j] Total annualized costs (before credit) minus recovery credit.

Table A-12. DUAL MECHANICAL SEAL SYSTEM COSTS FOR PUMPS (May 1980 dollars)

Per Pump Seal Cost Item	
Capital Cost[a]	
Seal	970
Seal installation	288
Barrier fluid system	1850
Barrier fluid degassing vent	4000
Total capital cost	7110
Annualized Cost[b]	
Capital recovery	
seals[c]	560
other capital[d]	1000
Maintenance charges[e]	360
Miscellaneous charges[f]	280
Total annualized cost	2200
Product Recovery Credit[g]	(210)
Net Annualized Cost [h]	1990

(xx) = Cost Savings

[a] From BID for proposed standards, Table 8-1.

[b] From BID for proposed standards, Table 8-5.

[c] Calculated as 0.58 x capital cost for seal.
Capital cost for seal = cost for new seal ($1250)
minus credit for old seal ($255 x 328.9/266.6) = $970.
Capital recovery credit per seal = 0.58 x $970 = $560.

[d] Calculated as: 0.163 x capital cost.

[e] Calculated as: 0.05 x capital cost.

[f] Calculated as: 0.04 x capital cost.

[g] Calculated as:
Emission Reduction x $215/Mg.
(from Table 10)

[h] Total annualized cost (before credit) minus product recovery credit.

Table A-13. COST EFFECTIVENESS OF PUMP CONTROLS
(May 1980 dollars)

Per pump Item/Control	Annual LDR	Quarterly LDR	Monthly LDR	Dual Seals
Net Annualized Cost[a]	180	110	130	1,990
VOC Emission Reduction (Mg/yr)[b]	0.21	0.70	0.82	0.99
Cost Effectiveness ($/Mg VOC)[c]	860	157	158	2,000
Incremental Cost Effectiveness ($/Mg VOC)[d]	860	(140)	170	10,900

(xx) = Cost Savings
LDR = Leak Detection and Repair

[a] From Tables 11 and 12.

[b] From Table 10.

[c] Calculated as :

$$\frac{\text{Net annualized costs (\$/yr)}}{\text{annual VOC emission reduction (Mg/yr)}}$$

[d] Calculated as:

$$\frac{\text{Net annualized cost of control technique} - \text{net annualized cost of next less restrictive control}}{\text{Annual VOC emission reduction of control technique} - \text{Annual VOC emission reduction of next less restrictive control}}$$

APPENDIX B

Regulatory Decisions Affecting Standards for SOCMI

Several of the decisions made on these standards (since they were proposed) affect EPA's position on standards of performance (Subpart VV) for equipment leaks of VOC within the Synthetic Organic Chemical Manufacturing Industry (SOCMI). These decisions are the result of new or additional analysis of the control techniques considered in the standards for petroleum refineries and SOCMI and, therefore, should be made consistent for these two standards. The decisions concern:

(1) alternative for determining a "capital expenditure,"
(2) clarification of reconstruction provisions,
(3) difficult-to-monitor valves in new units, and
(4) double block and bleed valve exemption.

The discussions of these decisions are found in Sections 2.2.3.1, 2.7, 4.2, and 5.0 of the BID for promulgated standards as they apply for petroleum refineries. The basis for the revisions to Subpart VV is consistent with these discussions. EPA knows of no reason not to make these revisions to Subpart VV and, therefore, based on a prudent use of its resources, is promulgating these revisions.

APPENDIX C

EVALUATION OF AVAILABLE LEAK DETECTION AND REPAIR DATA

Appendix C - EVALUATION OF AVAILABLE LEAK DETECTION AND REPAIR DATA

C.0 INTRODUCTION

As a part of their comments on the proposed NSPS for VOC fugitive emissions from petroleum refineries, two commenters (IV-D-25, IV-D-14) presented summary data from their plants and asked EPA to review these data. EPA requested the raw data for these summaries and requested other data to evaluate the NSPS in light of data from refinery leak detection and repair programs. EPA analyzed these data by comparing and contrasting, where possible, with the estimates used in preparing the BID for the proposed standards.

Sections C.2, C.3, and C.4 of this appendix are memoranda that provide summaries of the data, and describe the techniques used by EPA in analyzing the data. All of the data received were generated either as a result of or as a measure of the effectiveness of state or local regulations and, accordingly, an understanding of these regulations is needed. Therefore, the regulations on which the data are based are described in the memoranda. In most cases, data were submitted that allow direct quantitative comparison to the NSPS estimates. Where qualitative comparison of these data and the estimates used in the proposal BID are made, the reasons why the data are not directly related are presented and the uncertainties with the qualitative comparison are discussed.

Section C.2 presents data obtained from Texaco, U.S.A. (IV-D-25a, IV-D-33, IV-D-36). These data were generated under the requirements of the Louisiana State Implementation Plan, which requires quarterly monitoring of gas service components and annual monitoring of liquid service components. Texaco monitors additional components to those required by the proposed NSPS, and the data are therefore not directly comparable to the data used to support the NSPS in many cases. The Texaco data memorandum includes assumptions made by EPA in analyzing the data.

Section C.3 presents data obtained from facility inspections made by the South Coast Air Quality Management District (SCAQMD) and the Bay Area Air Quality Management District (BAAQMD) during a California Air Resources Board (CARB) petroleum refinery valve inspection program

(IV-D-31, IV-B-18). These data, as received by EPA, were the field data sheets from valve inspections at 12 refineries. The data are not based on inspection of entire process units, but only selected valves within selected process units. Again, EPA made several assumptions in analyzing the data, and these assumptions are stated in the memorandum.

Additional data were available from a study of the effectiveness of the South Coast Air Quality Management District (SCAQMD) Rule 466.1, performed by the EPA Office of Research and Development (ORD). The results of this study are summarized and evaluated in Section C.4.

C.1 DATA SUMMARY

Data are available from the memoranda in Sections C.2 through C.4 on initial leak frequency, leak occurrence rates, small valves, repair effectiveness, program costs, and monitoring time. This section summarizes these data and provides comparisons with the values used by EPA in estimating the impacts of the NSPS. The data discussed in this section have been arranged by topic rather than data source to provide for ease in locating specific information.

C.1.1 Initial Leak Frequency

Information on the initial leak frequencies at a few facilities can be obtained, by making assumptions, from the data supplied by Texaco (C.2) and the EPA analysis of the SCAQMD data (C.4). These data are shown in Table C-1.

For the Texaco data, initial leak frequency for each process unit was derived by assuming that the first period for which leak monitoring data was reported was indeed the first time the unit was monitored. Therefore, the percent of components found leaking at the first monitoring period is the initial leak frequency. The initial leak frequency for gas components varied from 0.0 percent to 14.8 percent, with a weighted average value of 6.5 percent. For liquid service components, the initial leak frequency varied from 0.0 percent to 17.0 percent, with a weighted average value of 2.8 percent. It should be noted that Texaco screens components not included in EPA's NSPS leak detection and repair program, such as valve flanges and valve bonnets. Since these sources are normally considered by EPA to have low leak frequencies, and they may represent a significant portion of the total number of components, EPA expects the initial leak frequency determined from the Texaco data to be understated compared to data based solely on testing of NSPS sources.

The EPA analysis of the SCAQMD data determined initial leak frequencies for five process units. These data show an initial leak frequency varying from 1.5 percent to 14.5 percent with an average value of 6.2 percent.

Since the CARB inspection data presented in Section C.3 is from inspection screening of facilities which have been performing leak detection and repair routinely, no initial leak frequencies can be generated.

In estimating the emission reductions for the refinery NSPS, EPA used an initial leak frequency of 10.5 percent.[1] While the Texaco data shows initial leak frequencies of 6.5 percent for gas service and 2.8 percent for liquid service components, the data can not be expected to be comparable to the EPA estimate due to the inclusion of infrequently leaking components as discussed above. The initial leak frequency of 6.2 percent found in the SCAQMD study is the result of a valve population identical to the EPA estimate basis, and is the result of 7,263 valve screenings. As the 6.2 percent initial leak frequency calculated indicates that EPA may have overstated the initial leak frequency for these plants, the LDAR model was run again using the 6.2 percent value. This run, which included other deviations from the original EPA estimates, is discussed in detail in Section C.4, and showed that leak detection and repair was a cost-effective control technique even with the lowered initial leak frequency.

3.1.2 Leak Occurrence Rate

Leak occurrence rates may be calculated for all three data sets. Table C-2 provides a summary of the average monthly occurrence rates for all data provided in the three memoranda.

Several factors must be considered when comparing these data with other information on leak occurrence rates. For the data provided by Texaco, the occurrence rates stated are for all components screened, which, as mentioned earlier, include a significant quantity of low leak frequency components. Therefore, the Texaco occurrence rates are probably understated significantly. The data presented for the CARB inspections represent valves only. However, CARB inspections are performed by monitoring component leaks at a distance of 1 centimeter from the component surface, rather than at the surface as required by Method 21. Since some leaks causing an instrument reading less than 10,000 ppm organics at 1 cm would likely read greater than 10,000 ppm at the surface, these occurrence rates are likely to be understated. In addition, the data from Texaco was presented by quarters and for the purpose of estimating occurrence rates, it was assumed that monitoring occurred on the first day of each quarter although monitoring may have actually occurred at any time during a 3-month period. Again, this discrepancy could cause understatement or overstatement of the occurrence rates.

In estimating the impacts of a leak detection and repair program, EPA used a leak occurrence rate of 1.27 percent/month, as discussed in Section C.4. As shown in Table C-2, the occurrence rates determined in the data memoranda varied from 0.05 to 0.6 percent/month for valves. The occurrence rates developed from the Texaco data are not compared to EPA estimates as they include measurement of sources that generally have a very low leak frequency. Although these occurrence rates indicate that EPA may have overestimated occurrence rates in the impacts analysis, it should be noted that EPA analyzed and consequently provided alternative standards for valves where low leak occurrence is found. Additionally, as discussed in Section C.4, EPA re-estimated the impacts of a leak detection and repair program based on a lower (0.6 percent/month) leak occurrence rate, and found the leak detection and repair program to still be cost effective.

C.1.3 Small Valves

The data provided by Texaco can be used to derive information on the leak characteristics of small valves. Table C-3 provides a listing of the leak incidences for small valves for line sizes less than or equal to 1 1/2 inches. For the three monitoring periods for which Texaco provided data, small valves accounted for 48 percent, 49 percent, and 32 percent of all valve leaks found, or an average for the three monitoring quarters of 45 percent of all valve leaks. Since it has been shown that valve size is relatively unrelated to the mass emission rate from a leaking valve,[2] the small (<1 1/2") valves in the Texaco refinery accounted for nearly one half of the valve leak emissions. Texaco did not provide small valve and large valve equipment counts, and therefore, the fraction of sources leaking could not be determined.

Data can also be obtained on the difficulty of performing on-line repairs on small valves. As described above, nearly one half of the leaking valves were 1 1/2" sizes or smaller. Table C-3 presents a summary of components in the Texaco program which required off line repair. As shown in the table, 68 small valves (≤2" line size) and 107 large valves (>2" line size) required off-line repair. Therefore, it appears that small valves are as repairable on-line as their larger counterparts. It should be noted that Texaco does not attempt to bypass components for off-line repair prior to unit shutdown, as will be required by the NSPS, but allows the leakers that are not repaired in two attempts at simple maintenance in service to continue to leak until a process unit shutdown occurs. Therefore, some of the components which were delayed until shutdown for repair in the Texaco program would be repaired under NSPS by bypassing the leaking valve for off-line repair. It should also be noted that some of the small valves listed in the table as requiring off-line repair were listed as large valves by Texaco due to the cutoff difference of 1 1/2" by Texaco and 2" by EPA. Therefore, the table actually shows a disproportionate amount of small valves requiring off-line repair.

C.1.4 Repair Effectiveness

Information can also be obtained from the Texaco data on the various aspects of repair effectiveness. Table 2 of memorandum C-2 provides data summarized from Texaco's listing of components for which repair was delayed (as explained in C.1.3). As can be seen, 7.4 to 26.5 percent of all leaks were delayed until turnaround for repair during the first five monitoring periods. For the sixth and seventh monitoring periods, 42.5 and 91.0 percent of all repairs were listed for turnaround, apparently because most of the leaks occurred in process units for which turnarounds were scheduled within the monitoring quarter. For the five quarters within which shutdowns of major units were not scheduled, the weighted average percentage of repairs which required shut down was 16.0 percent, while the weighted average percentage of repairs requiring shutdown for all quarters was 24.7 percent. As such, it would appear that simple, on-line repair was approximately 75.3 percent effective in the Texaco program. In estimating the annual repair labor cost[1], EPA assumed 75 percent of all valves can be repaired with simple on-line maintenance, and 25 percent of all valves require off-line repair. This basis seems to agree very well with Texaco's experience.

C.1.5 Program Costs

Texaco provided data on the cost of operating a Control Techniques Guideline (CTG)[3] based leak detection and repair program for a 1-year period. The program underway at Texaco is required by the Louisiana State Implementation Plan, and includes quarterly leak detection and repair of gas service components and annual leak detection and repair of liquid service components. As such, the program is similar to Regulatory Alternative II in the BID for proposed standards. Section C.2 provides a comparison of the costs provided by Texaco with the cost estimates provided in the BID for proposed standards. Due to differences in costing techniques, the costs cannot be directly compared. However, by adjusting both the Texaco and EPA costs slightly, as shown in the memo, some comparisons between the two costs can be made.

For example, Texaco reported a monitoring labor cost (in 1982 dollars) of $72,215/year for the entire refinery. Since EPA costs are estimated on a model unit basis, the Texaco refinery was broken down into model units as shown in the memo, and the EPA monitoring labor costs were totaled for the resulting model units. The resulting EPA labor cost for monitoring was approximately 50 percent lower than the Texaco monitoring costs. This is expected, however, as EPA labor cost estimates normally have other costs added to them to determine the total monitoring costs, such as recovery of the monitoring instrument capital costs and instrument calibration/maintenance costs. Since Texaco's monitoring program was performed by a contractor, the monitoring cost reported by Texaco would include these additional costs.

Texaco reported an annual repair cost (in 1982 dollars) of $5,301/year. While EPA estimates are normally much higher than this figure, Texaco's costs do not include any off-line repairs, as do the EPA repair cost estimates. Therefore, the EPA estimate for these costs were made by assuming a 10-minute repair time for the simple on-line repairs attempted by Texaco, and calculating the EPA cost estimate on the number of leaks encountered by Texaco. Texaco's reported repair cost of $5,301/year results in a unit cost (for 630 repairs) of $8.41 per component repair. Using the EPA estimate of 10 minutes at $18 per hour for simple repairs, with 40 percent overhead, results in a unit cost of $4.20 per repair. Again, the EPA estimate is about one-half the Texaco cost. Texaco made two repair attempts where necessary, which is not accounted for the EPA estimate. EPA normally assumes that 25 percent of all valves require off-line repair at 4 hours per valve, and 16 hours of repair labor is required for every pump seal. Hence, the EPA estimate used for comparison with Texaco's repair costs is significantly lower than the costs presented in the BID for the proposed standards.

The "overhead" cost reported by Texaco ($57,922) included the costs of tagging the components and setting up the monitoring program. Obviously, this cost is not recurring and, as such, is amortized over a 10-year period by EPA. As mentioned above, EPA estimates normally amortize non-recurring costs, including the capital costs of the monitoring instruments which were included in the "monitoring costs" by Texaco. As such, the EPA estimate in this case is significantly higher than the Texaco cost and corrects for the lower monitoring cost in the EPA estimate.

As shown in Table 4 of Section C.2, the Texaco total program costs were close to the EPA cost estimates for a similar program ($61,000 EPA vs. $71,000 Texaco after adjustment to reach the same cost basis), especially considering the differences in costing techniques employed.

C.1.6 Monitoring Time Data

The data provided on the California Air Resources Board (CARB) refinery valve inspection program included the "time monitored" for each component. The CARB data as presented in Section C.3 includes data from inspections in 12 refineries with a total of 93 process units, or 6,497 components. For these process units, monitoring time varied from 0.61 to 1.1 minutes/valve, with a weighted average value of 0.9 minutes/valve. In the BID for proposed standards, EPA estimated 1 minute/valve, which is nearly identical to that found in the CARB inspections.

C.1.7 References for Section C.1

1. VOC Fugitive Emissions in Petroleum Refining Industry - Background Information for Proposed Standards, EPA 450/3-81-015a, November 1982. Docket Item Number II-B-1.*

2. Memo, T.L. Norwood, PES, Inc., to Docket A-80-44, Small Valve Repair Cost Effectiveness. September 26, 1983. Docket Item Number II-B-8.*

3. "Control of Volatile Organic Compound Leaks from Petroleum Refinery Equipment" EPA450/2-78-036. June 1978. Docket Item Number IV-A-6.*

4. Assessment of Atmospheric Emissions from Petroleum Refining: Volume 3 Appendix B. EPA-600/2-80-075c, April 1980. Docket Item Number II-A-19.*

5. Fugitive Emission Sources of Organic Compounds - Additional Information on Emissions, Emission Reductions, and Costs. EPA-450/3-82-010, April 1982. Docket Item Number II-A-41.

*Document numbers refer to entries in Docket A-80-44, which can be found at the U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.

Table C-1. COMPARISON OF NEW INITIAL LEAK FREQUENCY DATA TO INITIAL LEAK FREQUENCY DATA USED IN NSPS DEVELOPMENT

Source	Serivce	Component Type	Number of Sources Screened	Initial Leak Frequency		
				Range(%)[a]	Average (%)[b]	95% C.I. (%)[c]
Texaco[d]	Gas	All	4,736	0.0 - 14.8	6.5	0.0 - 15.5
	Liquid	All	10,082	0.0 - 17.0	2.8	0.0 - 12.8
SCAQMD[e]	Gas and Liquid	Valves	7,263	1.5 - 14.5	6.2	0.0 - 15.7
Refinery[f] Assessment	Gas	Valves	570	0.0 - 27.3	10	3.2 - 19.8
	Liquid	Valves	995	0.0 - 19.2	11	5.0 - 17.0

a. Range of leak frequencies found for individual process units in the studies. Leak frequency = (#leaks/#screened) X 100%.

b. Weighted average leak frequency, calculated as:

$$\text{AVG.} = \frac{\sum_{i=0}^{N} (n_i \times P_i)}{N}$$

Where n_i = number of components in the ith process unit
P_i = percent leaking in the ith process unit
N = number of process units

c. 95 percent confidence interval for average, calculated as:

95% C.I. = AVG. + 2 S.D.
where S.D. = Standard Deviation

$$= \sqrt{\frac{\sum_{i=0}^{N} (\text{AVG.} - P_i)^2}{N}}$$

d. From Section C.2

e. From Section C.4

f. From Reference 5. Basis for NSPS analyses.

Table C-2. AVERAGE LEAK OCCURRENCE RATES

Refinery	Component Type	Service	No. of Sources	Occurrence Rate[a] (%/month)
Texaco; Convent, La.	All	Liquid	10,082	0.08
Texaco; Convent, La.	All	Gas	4,736	0.6
Tosco; Bakersfield, Ca.	Valves	Gas and Liquid	326	0.05[c]
Exxon; Benicia, Ca.	Valves	Gas and Liquid	858	0.6[c]
Chevron; Richmond, Ca.	Valves	Gas and Liquid	803	0.1[c]
ARCO; Carson, Ca.	Valves	Gas and Liquid	591	0.2[c]
Mobil; Torrance, Ca.	Valves	Gas and Liquid	338	0.3[c]
Fletcher Oil; Carson, Ca.	Valves	Gas and Liquid	317	0.4[c]
Champlin Oil; Wilmington, Ca.	Valves	Gas and Liquid	157	0.2[c]
Shell Oil; Carson, Ca.	Valves	Gas and Liquid	816	0.2[c]
Chevron; El Segundo, Ca.	Valves	Gas and Liquid	602	0.2[c]
Newhall; Newhall, Ca.	Valves	Gas and Liquid	152	0.1[c]
Powerine; Sante Fe Springs, Ca.	Valves	Gas and Liquid	576	0.4[c]
SCAQMD Summary	Valves	Gas and Liquid	7,263	0.6[d]
Proposal BID Basis	Valves	Gas and Liquid	---	1.27[e]

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[a] Average values weighted by number of sources as described in Footnote b of Table C-1.

[b] From Section C-2, Table 1, weighted average for refinery. Leaks defined as greater than 10,000 ppm organics concentration.

[c] From Section C-3, Table 1. Leaks defined as greater than or equal to 10,000 ppm organics concentration at 1 cm from source.

[d] From Section C-4, Table 4, weighted average of 5 units in two refineries.

[e] From Reference 1.

Table C-3. SMALL VALVE DATA SUMMARY

Monitoring Quarter	Small Valve[a] Leaks Detected	Large Valve[a] Leaks Detected	Small Valves[b] Requiring Off Line Repair	Large Valves[b] Requiring Off Line Repair
4Q 1981	-	-	5	10
1Q 1982	-	-	15	14
2Q 1982	93	102	11	21
3Q 1982	51	53	4	2
1Q 1983	-	-	2	7
2Q 1983	24	50	11	19
3Q 1983	-	-	20	34

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[a] From Section C.2 Table 3; small valves are those valves less than or equal to 1 1/2". "-" indicates that no data was provided by Texaco.

[b] Small valves defined as less than or equal to 2". From Section C.2, Table 2. Therefore, the "small valve" listings in these columns would include some of the "large valves" from the "leaks detected" listings (those valves greater than 1 1/2" and less than or equal to 2".

Section C.2

TEXACO DATA SUBMITTAL SUMMARY

A-80-44

MEMORANDUM

IV-B-22

DATE: November 11, 1983

TO: Docket A-80-44

FROM: T.L. Norwood, P.E., Pacific Environmental Services, Inc. TN

SUBJECT: Review and Summary of Leak Detection and Repair Program Data Supplied by Texaco, U.S.A.

Introduction

This memorandum summarizes the data supplied by Texaco, U.S.A as comments on the proposed new source performance standards for fugitive VOC emissions from petroleum refineries[1] and in response to EPA requests for additional information to clarify their original submittal.[2,3] This memorandum summarizes only those data supplied by Texaco that were sufficiently detailed to allow comparison with estimates provided by EPA in the background information document (BID) for the proposed standards.[4] The data supplied by Texaco were not supported by listings of component types for the process units (i.e., Texaco specified how many components were in each unit but did not break the unit totals into types of components). Some of the Texaco data, however, were sufficiently detailed to allow analysis.

Data Assumptions and Deviations with NSPS Programs

The Texaco facility for which the data were generated is subject to the State Implementation Plan for the State of Louisiana, which is based on the refinery CTG[5] requirements. The leak detection and repair program underway at the Texaco facility is, therefore, based on quarterly leak detection and repair of gas service components, annual leak detection and repair of liquid service components, and weekly visual inspection of pump seals. This program corresponds roughly to Regulatory Alternative II in the BID for proposed standards. There are, however, differences in the Texaco program and the BID Regulatory Alternative II program, as follows:

- The Texaco program includes screening of certain flanges, capped lines and other components not required in the NSPS alternatives. Since EPA believes these components have very low leak frequencies, their inclusion in a leak detection program would lower the overall leak frequency from that expected for a normal NSPS component mix. These "non-leakers" could represent a very significant portion of the total components monitored.

- The Louisiana SIP defines leaking components as those components with surface organic concentrations of greater than 10,000 ppm, while the refinery NSPS defines leaks as greater than or equal to 10,000 ppm surface organic concentrations. Those sources reading 10,000 ppm are thus considered leaks by the NSPS and not considered leaks by Texaco. Although this appears to be a minor difference, operators monitoring components may record the monitoring instrument readings in rounded numbers, with sources reading across a range being recorded as "10,000" ppm. These sources would be considered non-leakers by Texaco, reducing the measured leak incidence rate.
- Texaco uses OVA® leak detectors, which are calibrated with hexane at approximately 5,000 ppm. Method 21, as used in the refinery NSPS, currently specifies calibration with methane or hexane at approximately 10,000 ppm. The difference in calibration technique may result in small differences in the leak readings (and therefore the number of leaks). However, EPA feels that the differences in leak readings caused by the calibration differences should be small, if any.

Data Summary

Using the assumptions described in the footnotes to the tables, EPA was able to summarize the data collected by Texaco for comparison with EPA estimates for several leak detection and repair program parameters. These data must be used judicially, with careful attention given to the assumptions and program specifics stated. These data are presented in Tables 1 through 4, as follows:

Table 1 - Leak frequency and occurrence rate data

Table 2 - Delay of repair data

Table 3 - Small valve vs. large valve leak count data

Table 4 - Program annual costs.

References

1. Letter, J.M. McCrum, Texaco USA; to Central Docket Section, EPA; Comments on Proposed NSPS for Fugitive VOC Emissions from Petroleum Refineries. April 22, 1983. Docket Item Number IV-D-25a.
2. Letter, J.J. Lennox, Texaco, USA to R.E. Rosensteel, U.S. EPA; September 2, 1983. Docket Item Number IV-D-33.*
3. Letter, J.J. Lennox, Texaco, USA to R.E. Rosensteel, U.S. EPA; October 14, 1983. Docket Item Number IV-D-36.*
4. BID for proposed standards. Docket Item Number III-B-1.*

5. "Control of Volatile Organic Compound Leaks from Petroleum Refinery Equipment." EPA-450/2-78-036. June 1978. Docket Item Number II-A-6.

*Docket items refer to Docket Number A-80-44 in the EPA Central Docket Section, Waterside Mall, Washington, D.C.

Table 1. ESTIMATED RATE OF LEAK OCCURRENCE FOR TEXACO DATA - GAS SERVICE COMPONENTS[a]

Process Unit Number of Components	Date Screened[b]	Percent Leaking	Months Between Tests	Test-to-test 30- day Occurrence[c]	Cumulative Percent Leaking from Beginning of Test[d]	Months from Beginning of Test	30-day Occurrence from Beginning of Test[e]
VPS/VBU/GOU	10/81	1.0	-	-	-	-	-
1016	1/82	1.2	3	0.40	1.2	3	0.40
	4/82	1.0	3	0.33	2.2	6	0.37^{f}
	7/82	-g	-	-	-	-	-
	1/83	0.9	6	0.15	0.9	6	0.15
	4/83	0.7	3	0.23	1.6	9	0.18
	7/83	1.8	3	0.60	3.4	12	0.28^{f}
FCCU	10/81	1.4	-	-	-	-	-
715	1/82	0.56	3	0.19	0.56	3	0.19
	4/82	0.56	3	0.19	1.12	6	0.19
	7/82	0.98	3	0.33	2.1	9	0.23
	1/83	1.8	6	0.30	3.9	15	0.26
	4/83	0.14	3	0.047	4.04	18	0.22
	7/83	0.84	3	0.28	4.88	21	0.23^{f}
HTU-1	10/81	4.9	-	-	-	-	-
607	1/82	2.0	3	0.67	2.0	3	0.67
	4/82	1.5	3	0.50	3.5	6	0.58
	7/82	1.2	3	0.40	4.7	9	0.52
	1/83	1.8	6	0.30	6.5	15	0.43
	4/83	0.3	3	0.10	6.8	18	0.38
	7/83	0.5	3	0.17	7.3	21	0.35^{f}

Table 1. ESTIMATED RATE OF LEAK OCCURRENCE FOR TEXACO DATA GAS SERVICE COMPONENTS (continued)

Process Unit Number of Components	Date Screened[b]	Percent Leaking	Months Between Tests	Test-to-test 30- day Occurrence[c]	Cumulative Percent Leaking from Beginning of Test[d]	Months from Beginning of Test	30-day Occurrence from Beginning of Test[e]
CRU	10/81	10.2	-	-	-	-	-
450	1/82	8.9	3	3.0	8.9	3	3.0
	4/82	2.4	3	0.8	11.3	6	1.9
	7/82	2.9	3	1.0	14.2	9	1.6
	1/83	1.8	6	0.3	16.0	15	1.1
	4/83	0.9	3	0.3	16.9	18	0.94
	7/83	2.4	3	0.8	19.3	21	0.92[f]
ALKY	10/81	14.8	-	-	-	-	-
263	1/82	6.1	3	2.0	6.1	3	2.0[f]
	4/82	-[g]	-	-	-	-	-
	7/82	4.2	3	1.4	4.2	3	1.4
	1/83	3.8	6	0.6	8.0	9	0.88
	4/83	7.2	3	2.4	15.2	12	1.27
	7/83	2.3	3	0.8	17.5	15	1.17[f]
HTU-2	10/81	1.3	-	-	-	-	-
926	1/82	3.3	3	1.1	3.3	3	1.1[f]
	4/82	-[g]	-	-	-	-	-
	7/82	-[h]	-	-	-	-	-
	1/83	1.0	-	-	-	-	-
	4/83	1.9	3	0.6	1.9	3	0.6[f]
	7/83	-[i]	-	-	-	-	-
ARU	10/81	0.0	-	-	-	-	-
157	1/82	0.0	3	0.0	0.0	3	0.00
	4/82	0.0	3	0.0	0.0	6	0.00
	7/82	0.0	3	0.0	0.0	9	0.00
	1/83	0.6	6	0.1	0.6	15	0.040
	4/83	0.6	3	0.2	1.2	18	0.067
	7/83	0.0	3	0.2	1.2	21	0.057[f]

Table 1. ESTIMATED RATE OF LEAK OCCURRENCE FOR TEXACO DATA GAS SERVICE COMPONENTS (continued)

Process Unit Number of Components	Date Screened[b]	Percent Leaking	Months Between Tests	Test-to-test 30- day Occurrence[c]	Cumulative Percent Leaking from Beginning of Test[d]	Months from Beginning of Test	30-day Occurrence from Beginning of Test[e]
TGTU 24	10/81	8.3	-	-	-	-	-
	1/82	0.0	3	0.0	0.0	3	0.0[f]
	4/82	-[g]	-	-	-	-	-
	7/82	0.0	3	0.0	0.0	3	0.0
	1/83	0.0	3	0.0	0.0	9	0.0
	4/83	0.0	3	0.0	0.0	12	0.0
	7/83	0.0	3	0.0	0.0	15	0.0[f]
ETU/COB 200	10/81	0.0	-	-	-	-	-
	1/82	0.50	3	0.17	0.50	3	0.17
	4/82	1.0	3	0.33	1.5	6	0.25
	7/82	0.0	3	0.0	1.5	9	0.17
	1/83	0.0	6	0.0	1.5	15	0.10
	4/83	0.5	3	0.17	2.0	18	0.11
	7/83	0.0	3	0.0	2.0	21	0.095[f]
LDG 44	10/81	4.5	-	-	-	-	-
	1/82	0.0	3	0.0	0.0	3	0.0
	4/82	0.0	3	0.0	0.0	6	0.0[f]
	7/82	-[g]	-	-	-	-	-
	1/83	2.3	6	0.38	2.3	6	0.38
	4/83	4.5	3	1.5	6.8	9	0.76
	7/83	2.3	3	0.77	9.1	12	0.76[f]
TKG 240	10/81	1.3	-	-	-	-	-
	1/82	3.3	3	1.1	3.3	3	1.1[f]
	4/82	-[g]	-	-	-	-	-
	7/82	0.83	3	0.27	0.83	3	0.27
	1/83	6.3	6	1.1	7.13	9	0.79
	4/83	8.3	3	2.8	15.4	12	1.28
	7/83	1.7	3	0.57	17.1	15	1.14[f]

Table 1. ESTIMATED RATE OF LEAK OCCURRENCE FOR TEXACO DATA GAS SERVICE COMPONENTS (continued)

Process Unit Number of Components	Date Screened[b]	Percent Leaking	Months Between Tests	Test-to-test 30- day Occurrence[c]	Cumulative Percent Leaking from Beginning of Test[d]	Months from Beginning of Test	30-day Occurrence from Beginning of Test[e]
PW	10/81	2.1	-	-	-	-	-
94	1/82	2.1	3	0.70	2.1	3	0.70
	4/82	2.1	3	0.70	4.2	6	0.70[f]
	7/82	-[g]	-	-	-	-	-
	1/83	5.3	6	0.88	5.3	6	0.88
	4/83	6.4	3	2.1	11.7	9	1.30
	7/83	0.0	3	0.0	11.7	12	0.98[f]

Table 1. ESTIMATED RATE OF LEAK OCCURRENCE FOR TEXACO DATA - LIQUID SERVICE

Process Unit Number of Components	Date Screened[b]	Percent Leaking	Months Between Tests	Test-to-test 30- day Occurrence[c]	Cumulative Percent Leaking from Beginning of Test[d]	Months from Beginning of Test	30-day Occurrence from Beginning of Test[e]
VPS/VBU/COU	7/82	-[g]	-	-	-	-	-
2440	7/83	0.70	12	0.06	0.70	12	0.06[f]
FCCU	1/82	0.31	-	-	-	-	-
1934	4/83	0.31	15	0.021	0.31	15	0.021[f]
HTU-1	10/81	3.4	-	-	-	-	-
951	7/83	-[g]	-	-	-	-	-
CRU	10/81	17.0	-	-	-	-	-
401	-[i]	-	-	-	-	-	-
ALKY	4/82	-[g]	-	-	-	-	-
1203	1/83	4.4	9	0.49	4.4	9	0.49[f]
HTU-2	4/82	-[g]	-	-	-	-	-
542	-[i]	-	-	-	-	-	-
ARU	4/82	0.0	-	-	-	-	-
425	4/82	0.0	12	0.0	0.0	12	0.0[f]
TGTU	4/82	-[g]	-	-	-	-	-
68	4/83	0.0	12	0.0	0.0	12	0.0[f]

Table 1. ESTIMATED RATE OF LEAK OCCURRENCE FOR TEXACO DATA LIQUID SERVICE (concluded)

Process Unit Number of Components	Date Screened[b]	Percent Leaking	Months Between Tests	Test-to-test 30- day Occurrence[c]	Cumulative Percent Leaking from Beginning of Test[d]	Months from Beginning of Test	30-day Occurrence from Beginning of Test[e]
ETU/COB	7/82	0.0	–	–	–	–	–
81	1/83	0.0	6	0.0	0.0	6	0.0[f]
LDG	7/82	–[g]	–	–	–	–	–
221	1/83	1.8	6	0.3	1.8	6	0.3[f]
TKG	4/82	–[g]	–	–	–	–	–
1688	–[j]	–	–	–	–	–	–
PW	7/82	–[g]	–	–	–	–	–
128	1/83	0.0	6	0.0	0.0	6	0.0[f]

Footnotes to Table 1

[a] The number of gas and liquid components during the monitoring periods October 1981 through September 1983 are assumed to be constant and are based on the component summary in Table 1 of Docket Number A-80-44-IV-D-25a (page 8).

[b] The date screened is based on the assumption that components were monitoring the first month of the quarterly monitoring period. In reality, the components could have been monitored at any time during the quarter.

[c] Based on all leaks from the previous inspection being repaired and an assumption of linear leak occurrence. The leak frequency (percent leaking) divided by the number of months between tests estimates the 30-day leak occurrence rate.

[d] Based on all leaks at initial inspection being repaired and assuming that if the other inspection had not occurred, the leaks could have accumulated from inspection to inspection (leaks found are new leaks at each inspection).

[e] Same methodology as discussed in footnote b, except based on the initial inspection.

[f] These are the overall average monthly occurrence rates for a continuous series of screenings.

[g] These data could not be determined because the breakdown of gas and liquid components that were found leaking was not available. Therefore, this screening date begins a new monitoring period for the purpose of calculating the cumulative leak occurrence rate.

[h] Unit not in operation this quarter.

[i] Unit was shut down or partially shut down.

[j] No liquid components monitored in 1983.

Table 2. TEXACO DELAY OF REPAIR DATA SUMMARY[a]

QUARTER	NUMBER OF LEAKS DETECTED	REPAIRS SCHEDULED FOR TURNAROUND				TURNAROUND REPAIRS	
		NUMBER	PERCENT	# SMALL VALVES[b]	# LARGE VALVES[c]	NUMBER	PERCENT[d]
10/81 - 12/81	256	19	7.4	5	10	17	90
1/82 - 3/82	132	35	26.5	15	14	22	63
4/82 - 6/82	168	40	23.8	11	21	35	88
7/82 - 9/82[c]	74	13	17.6	4	2	11	85
1/83 - 3/83[e]	139	16	11.5	2	7	4	25[h]
4/83 - 6/83	87	37	42.5	11	19	8	22[h]
7/83 - 9/83[g]	78	71	91.0	20	34	--[f]	--[f]
TOTALS	934	231	24.7	68	107	85[h]	79[h]

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[a] Includes all process units and gas and liquid service components.

[b] Small valve is defined as 2 inches or less.

[c] Large valve is defined as greater than 2 inches.

[d] Percent repair effectiveness; number of turnaround repairs divided by number of repairs scheduled for turnaround.

[e] New leaks for this quarter were determined by examining leak data for previous quarters. Recurring leaks are considered to be new leaks for the purposes of this analysis.

[f] Cannot be determined from data

[g] Monitoring occurred during shutdown of ARO, TGTU, and HTU-2 (which contain 2,142 components).

[h] For some of the delayed repairs, shutdowns did not occur prior to the end of the reporting period. Therefore, no repair attempt was made for most components. The totals, therefore, include only the first 4 quarters.

Table 3. NUMBER OF LEAKS FOUND BY VALVE SIZE GROUP

Period	2nd Quarter 1982				3rd Quarter 1982				1st Quarter 1983			
	Valves 1-1/2" and Under		Valves Over 1-1/2"		Valves 1-1/2" and Under		Valves Over 1-1/2"		Valves 1-1/2" and Under		Valves Over 1-1/2"	
UNIT	No.	%[a]	No.	%[a]	No.	%[a]	No.	%[a]	No.	%[a]	No.	%[a]
VPS	5	71	2	29	3	27	8	73	2	15	11	85
FCCU	2	50	2	50	2	67	1	33	4	57	3	43
HTUI	15	41	22	59	5	63	3	37	5	71	2	29
CRU	53	57	40	43	21	64	12	36	4	31	9	69
ALKY	6	18	28	82	0	--	12	100	3	27	8	73
HTU-2	8	67	4	33	17	63	10	37	0	--	0	--
ARU	0	--	0	--	0	--	0	--	0	--	0	--
TGTU	1	50	1	50	0	--	0	--	0	--	0	--
ETU/COB	0	--	0	--	0	--	0	--	1	100	0	--
TK CAR/ TRUCK/ DOCK	1	50	1	50	0	--	0	--	1	10	9	90
TANKAGE FLARE/ ADD.	1	33	2	67	3	43	4	57	1	50	1	50
P/W	1	100	0	--	0	--	2	100	4	36	7	64
TOTAL PLANT	93	48	102	52	51	49	53	51	24	32	50	68

[a] % values indicate percentage of all valves leaking in that quarter.

Table 4. COMPARISON OF REPORTED TEXACO LEAK DETECTION AND REPAIR PROGRAM COSTS WITH EPA COST ESTIMATES

ITEM	TEXACO (1982 dollars)[1]	TEXACO (1980 dollars)[2]	EPA ESTIMATE (1980 dollars)
Monitoring Labor	$ 72,215/year	$59,060/year	$30,740/year[3]
Repair Labor	5,301	4,335	2,646/year[4]
Overhead/Setup	57,922	7,720[5]	27,500/year[6]
Total Program Costs	$135,488/year	$71,115/year	$60,886/year

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[1] From Reference.

[2] 1980 dollars calculated using Chemical Engineering Cost Indices: December 1982 = 316.1; May 1980 = 258.5; Ratio = 0.8178

[3] EPA Monitoring labor based on 4 each of Model Units A, B, and C per Table 4a, with Proposal BID Table F-12 labor estimates of 33.7 hours/year (A), 68.8 hours/year (B); and 202 hours/year (C). Labor at $18/hour, with 40% overhead added.

$/year = (33.7 + 68.8 + 202) hours x 4 units x $18/hour x 1.4

= $30,740

[4] EPA estimate based on 630 leaks detected in first 4 quarters (Table 2) by Texaco, at 10 minutes for each repair attempt. Labor at $18/hour with 40% added overhead.

$/year = 630 x 18 x 1.4 x 10/60 = $2,646/year

[5] EPA estimate based on amortizing initial setup costs for 10 years at 10% interest (capital cost x 0.163) and deflating to 1980 dollars per footnote 2 method.

[6] EPA estimate based costs of operating and maintaining 5 pairs of monitoring instruments (at $5,500/year each per BID for proposed standards Table 8-9) = $27,500/year.

Table 4a

FUGITIVE EMISSIONS COMPONENTS SUMMARY[a]

UNIT	No. of Components			EPA Model Plant
	Gas	Liquid	Total	
Vacuum Pipe Still, Visbreaking Unit & Gas Oil Unit (VPS)	1016	2440	3456	C
Fluid Catalytic Cracking Unit (FCCU)	715	1934	2649	C
Hydrotreating Unit #1 (HTU-1)	607	951	1558	C
Catalytic Reforming Unit (CRU)	450	401	851	B
Alkylation Unit (ALKY)	263	1203	1466	B
Hydrotreating Unit #2 (HTU-2)	926	542	1468	B
Amine Regeneration Unit (ARU)	157	425	582	B
Tail Gas Treating Unit (TGTU)	24	68	92	A
Effluent Treating Unit & Co Boilers (ETU/COB)	200	81	281	A
Tank Car & Truck Loading & Dock (LDG)	44	221	265	A
Tankage, Flares & Additives (TKG)	240	1688	1928	C
Pipeways (PW)	94	128	222	A
TOTAL	4736	10082	14818	

a. This Table is presented by Texaco as Table 1 in Reference 1. Model Plant designations added by EPA are based on the similarity of these model plants to the number of pieces of equipment shown for the Texaco units.

SECTION C.3

SUMMARY OF AVAILABLE CALIFORNIA AIR RESOURCES BOARD INSPECTION DATA

A-80-44

IV-B-18

MEMORANDUM

DATE: November 11, 1983

TO: Docket A-80-44

FROM: T.L. Norwood, P.E., Pacific Environmental Services, Inc. TLN

SUBJECT: Review and Summary of California Air Resources Board (CARB) Refinery Valves Inspection Program Data

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Introduction

This memorandum summarizes the California Air Resources Board (CARB) petroleum refinery fugitive emissions inspection data received by EPA. During the public comment period for the proposed new source performance standards for VOC fugitive emissions from petroleum refineries (48 FR 279), commenters on the standards (IV-D-8, IV-D-14, IV-D-15, IV-D-21) either requested that EPA obtain and analyze data on California leak detection and repair programs or the commenters used the California program results as a basis for their comments. EPA received the results of several CARB inspections, in three separate submittals, as follows:

- Letter from ARCO[1] with data from four facilities.
- Submittal from the Bay Area Air Quality Management District (BAAQMD)[2] with data from four bay area facilities.
- Letter from the South Coast Air Quality Management District (SCAQMD)[3] with data from eight facilities.

Data Description

The data EPA received from the CARB inspections were the field data sheets from the facility inspections. For each valve inspected, the following data were tabulated:

1. Source ID #
2. Time monitored
3 Date Monitored (for entire process unit)
4. Date last monitored (for entire process unit)
5. OVA® leak detector reading
6. TLV® leak detector reading
7. Component line size, rounded to nearest inch
8. Component type and service
9. Pre-and post-calibration results.

These inspection data were found to provide information that could be used to calculate leak occurrence rates and estimate average monitoring times. This memorandum presents these data analyses.

CARB Data Analysis

CARB is currently performing a separate analysis of these data, as they relate to local rules. CARB's analyses will include the following differences from this analysis:

- CARB is to "correct" the leak readings based on the measured calibration drift in the monitoring instrument between pre-test and post-test calibrations.
- Those sources measuring 10,000 ppm are not considered leaks by CARB, while those measuring greater than 10,000 ppm are leakers. EPA defines greater than or equal to 10,000 ppm a leak.
- CARB is attempting to change the calibration basis from methane to hexane for some data.

CARB should publish the results of their analysis in the near future.

EPA Data Analysis

From the field data received, EPA calculated the leak frequency based on those valves reading greater than or equal to 10,000 ppm organics and leak occurrence rate on a process unit and overall refinery basis. Leak frequency was calculated as the number of leaks divided by the number of components monitored, and expressed as a percentage. The 30-day leak occurrence rate was calculated by dividing the leak frequency by the number of months elapsed since the last inspection, and again expressing the result as a percentage. It should be noted that the sources were monitored with the instrument probe at 1 cm from the source. Under NSPS requirements (Method 21), the instrument probe must be placed at the surface of the component. While the relationship between the organics concentration and the distance form the source is not known precisely, readings at 1 cm from the source should normally be lower, reducing the measured leak frequency compared to measurements taken at the source.

Table 1 provides a summary of the data received by EPA on a refinery basis. These data are developed in Tables 2 through 13 for each refinery. These data should be used judiciously, as suggested by the following general comments on the CARB data.

Four Century Model 108 OVA were used along with four Bacharach TLV for this survey. The AQMD expressed concerns on the accuracy of TLV readings as calibration knobs are easily moved, precalibrations of TLV's were not always done with gas (however, post-calibration were), two teams did not use gas for either pre or post-calibrations, probe tips were sometimes contaminated, TLV's were not allowed to stabilize, and some TLV readings were potentially questionable due to be saturation of instrument on low scale. One CARB dilutor had leaks in the dilutor probe resulting in questionable readings and another required odd computations to obtain a reading. OVA data from the first day at Shell and the second day at Fletcher are questionable because one OVA did not hold calibration well. These data are footnoted on Tables 8 and 10. Some leaks are noted in excess of 10,000 ppm when the instrument was calibrated on methane.

Equivalent readings would be 15,800 ppm for AQMD rule based on 10,000 ppm hexane. Also, the determination of the background reading varied from CARB team to team.

As mentioned above, EPA also calculated the monitoring time required for each process unit. These times were calculated by subtracting the start time for a given process unit from the end time, and dividing the result by the number of components in the unit. Where gaps in the monitoring time from one component to the next of more than 15 or 20 minutes were noted, the time of these gaps was subtracted from the monitoring time. Shorter gaps (< 15 minutes) were not subtracted, however, to allow for normal operator breaks, instrument flameouts, and other normal break periods.

References

1. Letter, P.M. Kaplow, ARCO to Central Docket Section, U.S.E.P.A.; Results of Refinery Inspections. June 15, 1982. Docket Item Number IV-D-31.*

2. Memo, T.L. Norwood, PES, Inc., to Docket A-80-44, Local Air Quality Management District Refinery Inspection Data. November 21, 1983. Docket Item Number IV-B-18.*

3. Letter, D.M. Newton, SCAQMD to S.R. Wyatt, U.S. E.P.A.; Refinery Inspection Data. October 24, 1983. Docket Item Number IV-D-37.*

*Document numbers refer to entries in Docket A-80-44, which can be found at the U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.

Table 1. SUMMARY OF CALIFORNIA AIR RESOURCES BOARD INSPECTION DATA

REFINERY / LOCATION	NUMBER OF SOURCES INSPECTED	MONITORING TIME (min/source)	OVA[a]			TLV[a]		
			PERCENT[b] LEAKING	95% C.I.[c]	30 DAY OCCURRENCE[d]	PERCENT[b] LEAKING	95% C.I.[c]	30 DAY OCCURRENCE[d]
Tosco Corp. Bakersfield	326	0.61	0.31	0 - 0.93	0.02	0.61	0 - 1.47	0.05
Shell Oil Co. Martinez	816	1.1	3.7	2.4 - 5.0	1.27	4.3	2.9 - 5.7	1.61
Exxon Co. Benicia	858	0.72	3.6	2.3 - 4.9	0.50	4.0	2.7 - 5.3	0.56
Chevron USA Richmond	803	1.02	2.1	1.1 - 3.1	0.17	1.7	0.8 - 2.6	0.14
Arco Carson	591	0.8	1.5	0.5 - 2.5	0.21	1.5	0.5 - 2.5	0.18
Mobil Oil Corp. Torrance	338	1.1	3.6	1.6 - 5.6	0.31	3.3	1.4 - 5.2	0.29
Fletcher Oil Carson	317	1.1	2.2	0.6 - 3.8	0.42	1.9	0.4 - 3.4	0.36
Champlin Oil Wilmington	435	0.9	1.4	0.3 - 2.5	0.27	1.1	0.1 - 2.1	0.21
Shell Oil Carson	683	0.9	1.3	0.4 - 2.2	0.24	1.2	0.4 - 2.0	0.21
Chevron USA El Segundo	602	1.1	3.2	2.4 - 4.0	0.25	2.3	1.1 - 3.5	0.18
Newhall Newhall	152	1.1	0.7	0.0 - 2.1	0.14	0.7	0.0 - 2.1	0.14
Powerine Santa Fe Springs	576	0.8	2.1	0.9 - 3.3	0.51	1.6	0.6 - 2.6	0.39
TOTAL	6,497	0.9	2.4	2.0 - 2.8	0.41	2.3	1.9 - 2.7	0.41

a. OVA refers to the Foxboro, Inc. organic vapor analyzer; TLV refers to the Bacarach, Inc. "Sniffer" organic vapor analyzer.

b. Leaks are defined as those sources measuring greater than or equal to 10,000 ppm organics concentration at a distance of one centimeter.

c. 95% C.I. = 95 percent confidence interval of percent leaking. This is estimated as P ± 2SD, where P = percent leaking;

$$\text{SD} = \text{standard deviation} = \sqrt{\frac{P(100-P)}{N}}$$, and N = number of sources inspected.

d. The 30-day occurrence rates are calculated using the number of sources inspected, the number of days from the last plant inspection to the CARB inspection, and the measured percent leaking:

$$\text{30 day occurrence rate} = \frac{\text{percent leaking}}{\text{number of 30-day periods}} \quad \text{and} \quad \text{plant-weighted rate} = \frac{\sum(N_{\text{each process unit}} \times \text{30 day occurrence})}{N_{\text{total sources inspected}}}$$

Table 2. CARB FACILITY INSPECTION SUMMARY FOR TOSCO, BAKERSFIELD

PROCESS UNIT	DATE OF LAST PLANT INSPECTION	DATE OF CARB INSPECTION	NUMBER OF SOURCES INSPECTED	MONITORING TIME (min/source)	OVA			TLV		
					NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE	NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE
REFORMER	5/20/82	6/15/83	164	0.82	1	0.6	0.046	2	1.2	0.092
HDS #1	6/9/82	6/20/83	162	0.4	0	0	0	0	0	0
TOTAL	—	—	326	0.61	1	0.31	0.023	2	0.61	0.046

SOURCE: Reference 2.

NOTE: Terms and calculation procedures are defined in the footnotes to Table 1.

Table 3. CARB FACILITY INSPECTION SUMMARY FOR SHELL OIL, MARTINEZ

PROCESS UNIT	DATE OF LAST PLANT INSPECTION	DATE OF CARB INSPECTION	NUMBER OF SOURCES INSPECTED	MONITORING TIME (min/source)	OVA NUMBER LEAKING	OVA PERCENT LEAKING	OVA 30-DAY OCCURRENCE	TLV NUMBER LEAKING	TLV PERCENT LEAKING	TLV 30-DAY OCCURRENCE
LPG Storage	9/3/82	6/20/83	50	1.9	5	10.0	1.03	7	14.0	1.45
LPG Loading	2/1/83	6/21/83	72	2.1	5	6.9	1.50	6	8.3	1.77
LPG Storage	9/3/82	6/21/83	31	1.8	6	19.4	2.00	6	19.4	2.00
FCCU	5/23/83	6/21-22/83	162	0.99	1	0.62	0.62	1	0.62	0.62
CFH	a	6/22/83	63	0.76	0	0	0.0	0	0	0.0
CGH	b	6/22/83	15	1.13	0	0	0.0	1	6.7	12.4
CFH	c	6/23/83	85	0.73	0	0	0.0	0	0	0.0
Alkylation	d	6/23/83	160	1.00	7	4.4	1.47	7	4.4	1.47
Utilities	e	6/24/83	120	0.88	3	2.5	2.87	3	2.5	2.87
Catalytic Reformer	f	6/24/83	58	1.31	3	5.2	2.60	4	6.9	3.45
TOTAL	-	-	816	1.1	30	3.7	1.27	35	4.3	1.61

SOURCE: Reference 2.

NOTE: Terms and calculation procedures are defined in the footnotes to Table 1.

[a] 5-1-83 62 sources
No date available 1 source

[b] 5-23-83 6 sources
6-15-83 9 sources

[c] 2-1-83 37 sources
5-1-83 48 sources

[d] 2-1-83 18 sources
5-1-83 142 sources

[e] 2-1-83 14 sources
6-13-83 6 sources
6-15-83 89 sources

For 11 sources, last plant date unknown. Average of remaining 109 sources used.

[f] 2-1-83 4 sources
3-31-83 21 sources
5-23-83 33 sources

Table 4. CARB FACILITY INSPECTION SUMMARY FOR EXXON USA, BENICIA

PROCESS UNIT	DATE OF LAST PLANT INSPECTION	DATE OF CARB INSPECTION	NUMBER OF SOURCES INSPECTED	MONITORING TIME (min/source)	OVA			TLV		
					NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE	NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE
POWERFORMER	9/21/82	6/14/83	147	0.86	2	1.4	0.16	2	1.4	0.16
ALKYLATION	12/5/82	6/15/83	160	1.2	15	9.4	1.57	18	11.3	1.88
CATALYTIC LIGHT ENDS	9/2/82	6/16/83	138	0.56	3	2.2	0.16	3	2.2	0.16
HYDROTREATER DHF and JK	9/2/82	6/16/83	24	0.50	2	8.3	0.87	2	8.3	0.87
HYDROTREATER PS/VLE	12/15/82	6/16/83	48	0.40	0	0	0.0	0	0	0.0
HYDROTREATER VLE	9/2/82	6/16/83	24	0.38	1	4.2	0.44	1	4.2	0.44
HYDROTREATER PS/VLE	9/2/82	6/16/83	22	0.45	0	0	0.0	0	0	0.0
VIRGIN LIGHT ENDS	9/2/82	6/16/83	55	0.55	2	3.6	0.38	2	3.6	0.38
VIRGIN LIGHT ENDS	9/2/82	6/16/83	48	0.56	0	0	0.0	0	0	0.0
LPG STORAGE	11/12/82	6/16/83	48	0.42	0	0	0.0	0	0	0.0
LPG LOADING RACK	11/12/82	6/17/83	96	0.75	6	6.3	0.87	6	6.3	0.87
LPG STORAGE PIPEWAY	11/12/82	6/16/83	48	0.46	0	0	0.0	0	0	0.0
TOTAL		—	858	0.72	31	3.6	0.50	34	4.0	0.56

SOURCE: Reference 2.

NOTE: Terms and calculation procedures are defined in the footnotes to Table 1.

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Table 5. CARB FACILITY INSPECTION SUMMARY FOR CHEVRON, RICHMOND

PROCESS UNIT	DATE OF LAST PLANT INSPECTION	DATE OF CARB INSPECTION	NUMBER OF SOURCES INSPECTED	MONITORING TIME (min/source)	OVA			TLV		
					NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE	NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE
CRUDE (LPG PROCESSING)	5/4/82	6/14/83	48	1.2	0	0	0	0	0	0
FURNACE FEED	5/4/82	6/14/83	48	1.0	0	0	0	0	0	0
H_2S RECOVERY	4/27/82	6/14/83	44	0.80	0	0	0	0	0	0
FUEL GAS AT #5 NAPHTHA HYDROTREATER	4/15/82	6/16/83	20	0.75	0	0	0	0	0	0
FCCU	6/21/82	6/15/83	160	0.88	5	3.1	0.26	5	3.1	0.26
H_2SO_4 ALKYLATION	7/26/82	6/15/83	63	1.2	0	0	0	0	0	0
NAPHTHA HYDROTREATER	4/15/82	6/16/83	160	0.89	2	1.3	0.09	2	1.3	0.09
RENOFURMER	6/15/82	6/16/83	170	1.1	6	3.5	0.29	5	2.9	0.24
LPG STORAGE	6/11/82	6/17/83	90	1.4	4	4.4	0.36	2	2.2	0.18
TOTAL	—	—	803	1.02	17	2.1	0.17	14	1.7	0.14

SOURCE: Reference 2.

NOTE: Terms and calculation procedures are defined in the footnotes to Table 1.

Table 6. CARB FACILITY INSPECTION SUMMARY FOR ARCO, CARSON

PROCESS UNIT	DATE OF LAST PLANT INSPECTION	DATE OF CARB INSPECTION	NUMBER OF SOURCES INSPECTED	MONITORING TIME (min/source)	OVA			TLV		
					NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE	NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE
LIGHT ENDS	11/2/82	5/6/83	90	0.6	1	1.1	0.16	1	1.1	0.16
FCCU	8/18/82	5/2/83	48	1.0	1	2.1	0.25	0	0	0
COKER	9/30/82	5/2/83	52	0.9	0	0	0	0	0	0
LPG STORAGE	12/19/82	5/3/83	100	0.8	3	3.0	0.67	3	3.0	0.67
HYDRO-TREATER	6/8/82	5/5/83	90	0.6	0	0	0	0	0	0
ALKYLATION	5/12/82	5/4/83	120	0.7	4	3.3	0.28	3	2.5	0.21
REFORMER 2	10/1/82	4/28/83	71	0.8	0	0	0	0	0	0
REFORMER 1	9/24/82	4/28/83	20	1.0	0	0	0	0	0	0
TOTALS	–	–	591	0.8	9	1.5	0.21	7	1.5	0.18

SOURCE: Reference 1.

NOTE: Terms and calculation procedures are defined in the footnotes to Table 1.

Table 7. CARB FACILITY INSPECTION SUMMARY FOR MOBIL, TORRANCE

PROCESS UNIT	DATE OF LAST PLANT INSPECTION	DATE OF CARB INSPECTION	NUMBER OF SOURCES INSPECTED	MONITORING TIME (min/source)	OVA			TLV		
					NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE	NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE
COKER, S	6/7/82	4/26/83	45	1.6	1	2.2	0,20	1	2.2	0,20
COKER, N	6/7/82	4/26/83	35	1.2	0	0	0	0	0	0
HYDRO-TREATER	5/24/82	4/26-27/83	76	1.3	6	7.9	0.70	5	6.7	0.60
REFORMER	5/24/82	4/27/83	75	1.4	5	6.7	0.59	5	6.7	0,59
LPG STORAGE	7/6/82	4/28/83	52	0.7	0	0	0	0	0	0
LPG LOADING	7/8/82	4/28/83	55	0.6	0	0	0	0	0	0
TOTALS	—	—	338	1.1	12	3.6	0,31	11	3.3	0,29

SOURCE: Reference 1.

NOTE: Terms and calculation procedures are defined in the footnotes to Table 1.

Table 8. CARB FACILITY INSPECTION SUMMARY FOR FLETCHER OIL, CARSON

PROCESS UNIT	DATE OF LAST PLANT INSPECTION	DATE OF CARB INSPECTION	NUMBER OF SOURCES INSPECTED	MONITORING TIME (min/source)	OVA			TLV		
					NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE	NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE
FCCU	12/8-12/82	4/26/83	70	1.8	0	0	0	0	0	0
FUEL GAS	11/29/82	5/4/83	93	0.9	3 *	3.2	0.62	3	3.2	0.62
REFORMER	11/29/82	5/4/83	77	0.8	1 *	1.3	0.25	1	1.3	0.25
LPG	11/29/82	5/4/83	77	1.1	3 *	3.9	0.78	2	2.6	0.50
TOTALS	—	—	317	1.1	7 *	2.2	0.42	6	1.9	0.36

SOURCE: Reference 1.

NOTE: Terms and calculation procedures are defined in the footnotes to Table 1.

* The OVA did not hold calibration well during testing of these units

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Table 9. CARB FACILITY INSPECTION SUMMARY FOR CHAMPLIN OIL, WILMINGTON

PROCESS UNIT	DATE OF LAST PLANT INSPECTION	DATE OF CARB INSPECTION	NUMBER OF SOURCES INSPECTED	MONITORING TIME (min/source)	OVA			TLV		
					NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE	NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE
COKER, OLD	12/21/82	4/26/83	16	1.2	0	0	0	0	0	0
COKER, NEW	12/21/82	4/26/83	27	0.9	0	0	0	0	0	0
FCCU	1/83	4/26/83	42	1.3	1	2.4	0.62	1	2.4	0.62
NAPHTHA HYDROTREATER	9/10/82	4/26/83	24	1.0	0	0	0	0	0	0
REFORMER	1/5/83	4/27/83	75	1.0	1	1.3	0.35	1	1.3	0.35
NAPHTHA HYDROTREATER	11/4/82	4/27/83	51	0.7	0	0	0	0	0	0
FUEL GAS PROCESSING	11/15/82	4/28/83	100	0.6	0	0	0	0	0	0
LPG STORAGE	12/15/82	4/28/83	100	1.1	4	4.0	0.92	3	3.0	0.67
TOTALS	—	—	435	0.9	6	1.4	0.27	5	1.1	0.21

SOURCE: Reference 2.

NOTE: Terms and calculation procedures are defined in the footnotes to Table 1.

Table 10. CARB FACILITY INSPECTION SUMMARY FOR SHELL, CARSON

PROCESS UNIT	DATE OF LAST PLANT INSPECTION	DATE OF CARB INSPECTION	NUMBER OF SOURCES INSPECTED	MONITORING TIME (min/source)	OVA			TLV		
					NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE	NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE
FCCU	[illegible]	4/27/83	43	1.6	1 *	2.3	[illegible]	0	0	0
ALKYLATION	11/22/82	4/27/83	116	1.1	0 *	0	0	0	0	0
CATALYTIC REFORMER	11/15/82	4/20/83	83	0.7	1	1.2	0.19	1	1.2	0.19
ISOMER-IZATION	[illegible]	5/2/83	95	1.1	2	2.1	[illegible]	2	2.1	[illegible]
FCC/FUEL GAS SYSTEM	4/27/82	5/3/83	120	0.6	0	0	0	0	0	0
ALKYLATION LPG STORAGE	11/22/82	5/3/83	71	0.9	5	7.0	1.30	5	7.0	1.30
LPG/TRUCK RACK	3/27/83	5/3/83	25	0.7	0	0	0	0	0	0
HYDROTREATER	11/15/82	5/5/83	85	0.8	0	0	0	0	0	0
COKER	11/23/82	5/5/83	45	0.8	0	0	0	0	0	0
TOTAL	—	—	683	0.9	9	1.3	[illegible]	8	1.2	[illegible]

SOURCE: Reference 1.

NOTE: Terms and calculation procedures are defined in the footnotes to Table 1.

*The OVA did not hold calibration well during testing of these units.

Table 11. CARB FACILITY INSPECTION SUMMARY FOR CHEVRON, EL SEGUNDO

PROCESS UNIT	DATE OF LAST PLANT INSPECTION	DATE OF CARB INSPECTION	NUMBER OF SOURCES INSPECTED	MONITORING TIME (min/source)	OVA			TLV		
					NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE	NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE
ISOMAX NAPHTHA HYDROTREATER	6/3/82	4/27/83	45	1.3	2	2.9	0.27	2	2.9	0.27
ISOMAX CAT. REFORMER	6/2/82	4/27/83	31	1.3	0	0	0	0	0	0
No.1 H_2S/NH_3	6/4/82	4/27/83	21	1.1	1	4.8	0.44	1	4.8	0.44
FCCU	4/20/82	4/28/83	45	1.7	3	6.7	0.54	3	6.7	0.54
No.2 H_2S	4/20/82	5/2/83	48	0.9	2	4.2	0.33	2	4.2	0.33
FCCU	4/20/82	5/2/83	21	1.1	1	4.8	0.38	0	0	0
Aromatic REFORMER	5/4/82	5/2/83	32	1.6	3	9.4	0.77	1	3.1	0.26
ALKYLATION	4/2/82	5/3/83	119	1.5	6	5.0	0.38	5	4.2	0.32
DELAYED COKER	7/22/82	5/4/83	58	0.8	1	1.7	0.18	0	0	0
#5 H_2S	3/8/83	5/4/83	48	0.7	0	0	0	0	0	0
#1 REFORMER	4/26/83	5/5/83	46	0.7	0	0	0	0	0	0
#2 NAPHTHA HYDROTRTR	1/28/83	5/5/83	40	0.7	0	0	0	0	0	0
LPG LOADING	12/15/82	5/5/83	48	0.6	0	0	0	0	0	0
TOTAL	—	—	602	1.1	19	3.2	0.25	14	2.3	0.18

SOURCE: Reference 2.

NOTE: Terms and calculation procedures are defined in the footnotes to Table 1.

Table 12. CARB FACILITY INSPECTION SUMMARY FOR NEWHALL, NEWHALL, CALIFORNIA

PROCESS UNIT	DATE OF LAST PLANT INSPECTION	DATE OF CARB INSPECTION	NUMBER OF SOURCES INSPECTED	MONITORING TIME (min/source)	OVA			TLV		
					NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE	NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE
HYDROBOND	12/20/82	5/5/83	72	1.4	0	0	0	0	0	0
CAT REFORMER	12/16/82	5/5/83	2	0.5	0	0	0	0	0	0
CAT REFORMER	12/16/83	5/6/83	78	0.9	1	1.3	0.28	1	1.3	0.28
TOTAL	—	—	152	1.1	1	0.7	0.14	1	0.7	0.14

SOURCE: Reference 2.

NOTE: Terms and calculation procedures are defined in the footnotes to Table 1.

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Table 13. CARB FACILITY INSPECTION SUMMARY FOR POWERINE, SANTA FE SPRINGS

PROCESS UNIT	DATE OF LAST PLANT INSPECTION	DATE OF CARB INSPECTION	NUMBER OF SOURCES INSPECTED	MONITORING TIME (min/source)	OVA			TLV		
					NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE	NUMBER LEAKING	PERCENT LEAKING	30-DAY OCCURRENCE
PLATFORMER	12/17/82	5/2/83	86	0.8	1	1.2	0.3	1	1.2	0.3
FCC	1/11/83	5/2/83	41	0.9	2	4.9	1.2	1	2.4	0.6
COKER	11/23/82	5/3/83	54	0.7	1	1.9	0.4	1	1.9	0.4
HYDRO-TREATER	1/26/83	5/3/83	50	0.5	0	0	0	0	0	0
HYDRO-CRACKER	1/21/83	5/3/83	31	0.6	0	0	0	0	0	0
LPG LOADING	12/15/82	5/3/83	50	1.0	1	2.0	0.4	1	2.0	0.4
LPG STORAGE	12/15/82	5/3/83	50	1.3	3	6.0	1.3	1	2.0	0.4
LIGHT ENDS ISOMERIZATION	1/21/83	5/4/83	101	0.9	3	3.0	0.9	3	3.0	0.9
FUEL GAS	1/11/83	5/4/83	113	0.5	1	0.9	0.3	1	0.9	0.3
TOTAL	—	—	576	0.8	12	2.1	0.5	9	1.6	0.4

SOURCE: Reference 2.

NOTE: Terms and calculation procedures are defined in the footnotes to Table 1.

SECTION C.4

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT STUDY DATA SUMMARY

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

SEP 1 5 1983

A-80-44

IV-B-11

MEMORANDUM

SUBJECT: Review of ORD Study of South Coast Air Quality Management District Fugitive Emissions

FROM: K. C. Hustvedt
Petroleum Section, CPB/ESED (MD-13)

TO: James F. Durham, Chief
Petroleum Section, CPB/ESED (MD-13)

BACKGROUND AND CONCLUSIONS

Several years ago, we requested that the Office of Research and Development (ORD) analyze the effectiveness of local rules at reducing fugitive emissions. The ORD contracted with Radian and GCA to perform fugitive emission testing at two refineries operating under the South Coast Air Quality Management District (SCAQMD) Rule 466.1 on leakage from valves and flanges. As possible, the contractors also gathered historical data on the implementation of Rule 466.1 and other information. The results of this study are reported in "Evaluation of the Maintenance Effect on Fugitive Emissions from Refineries in the South Coast Air Quality Management District," EPA-600/7-82-049, January 1982.[1]

An analysis of the absolute effectiveness of local rules based on the historical Rule 466.1 implementation data is not possible because of changes in the sample populations from test to test. However, several general observations can be made from this study. The rate of leak occurrence found in this study is similar to what the results of the maintenance study[2] would predict for the given initial leak frequencies. At one of the refineries where maintenance was performed whenever the contractor found a leak, greater than 99 percent of the leaks were repaired within 2 days with a resulting calculated emission reduction of 95.7 percent. Further, as an indicator of the reliability of portable detectors at identifying leaking sources, 97.3 percent of the sources identified as leaking by the original inspection team were also identified as leaking by a second inspection team. Overall only 2 of the 521 sources screened (99.6 percent) by two independent screening teams had different leak/no leak determinations. Regarding the ability to screen all valves in a process unit, 12.3 percent of the overall valves were not screened for various reasons, including high background organics concentration, location, and instrument problems. Only 3.3 percent of the overall valves could not be monitored because they were difficult to monitor without extraordinary aids such as scaffolding or a cherry picker. Finally, by assessing pump seal maintenance records, it was determined that pump seal concentration is essentially independent from seal age and that both operating and spare mechanical pump seals are replaced on average every 1 to 1.5 years with 90 percent of the seals replaced within 3 years. All of these data support the estimates we made in the development of the proposed refinery equipment leaks new source performance standard (NSPS). Using the results of the SCAQMD study in Radian's leak detection and repair (LDAR) model[3], I estimated the cost effectiveness of routine monitoring programs. This analysis shows that replacing their present programs with monthly monitoring would have a cost effectiveness of about 50 dollars per megagram ($/Mg) and that the incremental cost effectiveness of monthly monitoring over quarterly monitoring for these plants would be less than 1000 $/Mg.

DISCUSSION

The analysis of the effectiveness of Rule 466.1 in the SCAQMD study relies upon historical data developed by the refineries in their implementation of Rule 466.1. Reviewing the trend in percent of sources leaking from inspection to inspection should give an indication of the effectiveness of Rule 466.1 at reducing fugitive emissions. In this testing, however, the number of sources tested often changed more than the number of sources found leaking, indicating that some unknown portion of the leaks detected after the first inspection may have been leaking at the first inspection but were not screened. For this reason, no attempt has been made to estimate the overall effectiveness of Rule 466.1 at reducing fugitive emissions. There are data in the SCAQMD study that can be compared to numbers we used in the proposed refinery equipment leaks NSPS and these are discussed in the following sections.

Occurrence Rate - Table 4-16 in the SCAQMD report presents historical data on the implementation of Rule 466.1. These data are used to estimate leak occurrence in Table 1 based on the following assumptions:

1. All leaks are screened and repaired on the last day of the month (to develop the time intervals).

2. Leak recurrence is insignificant because of the follow-up screening and maintenance performed under Rule 466.1 for repaired leaks.

3. Changes in instrument, instrument operator, calibration gas, and number of sources screened have a small effect on the percent of sources found leaking.

4. If no leak detection and repair were performed, leaks would accumulate from the previous inspection to the next inspection (to estimate overall occurrence rates from the beginning to the end of the test period).

All of these assumptions appear reasonable except possibly that there is only a small effect from the change in number of sources screened.

Table 1 shows that the 30-day occurrence rate from test to test ranged from 0.24 to 1.80 percent and that the 30-day occurence rate for the whole test ranged from 0.35 to 0.94 percent for the five units tested. Table 2 shows a comparison of these overall occurrence rates to the ones used in the proposed refinery equipment leak NSPS. As you can see, these rates compare quite favorably, indicating refineries operating under the SCAQMD Rule 466.1 have similar occurrence rates to those we estimated on the national average in developing the refinery equipment leaks NSPS.

Maintenance Effectiveness - Chevron used Radian's testing as their annual check under SCAQMD Rule 466.1. For this Rule, all leaks must be repaired within 2 days. Of the 347 valve leaks detected by Radian, 344 were repaired by means ranging from simple packing adjustment to sealant injection and valve replacement. The remaining three valves were taken out of service. This equates to a maintenance effectiveness of 99.1 percent within 2 days, as opposed to the estimate of 90 percent repaired within 15 days in the refinery leaks NSPS. The reduction in mass emissions due to maintenance was estimated based on screening valves to be 95.7 percent. In the refinery leaks NSPS, successful leak repair was estimated to result in an emission reduction of 97.7 percent. As with occurrence rates, the estimates of maintenance effectiveness in the SCAQMD study compare favorably with those used in the refinery leaks NSPS.

Test Method Reliability - As in all research efforts, a quality assurance (QA) check was performed during the SCAQMD testing by the EPA contractors. As a part of this QA effort, approximately 5 percent of the sources were independantly screened by a second screener. In this QA testing, 37 sources were found to be leaking during the initial screening and 36 of these sources, or 97.3 percent, were also found to leaking during the second screening. A total of 521 sources were screened in the QA effort, and all but 2 of the sources were either found to be leaking by both screeners or found not to be leaking by both screeners.

Difficult-to-Monitor Sources - During fugitive emission screening programs by the EPA contractors, several sources are not monitored for various reasons. To assess the magnitude of this problem, Radian identified the reasons sources were not screened during their testing. Table 3 summarizes these results from Table 4-1 of the SCAQMD report for gas and light-liquid service valves only. As shown in Table 3, most of the sources not screened (8.6 percent of the overall sources and almost 70 percent of those not screened) could have been screened if ladders had been provided. An additional 3.3 percent of the 12.6 percent not screened (about a fourth) were also not screened because of location, but these sources would have needed extraordinary aids such as scaffolding or a movable crane (cherry picker) to have been screened. The remaining few sources, about 0.6 percent of the total, that were not screened were for temporary reasons, such as the source out of service, sampling problems, or the plant not allowing the contractor access to certain areas.

Pump Seal Replacement - The maintenance history of pump seals was acquired by examining refinery records. Data were available on 98 pumps with a total of 544 seal replacements. A comparison of the screening value and the months since most recent seal replacement indicated a slight positive relationship (concentration increasing with time), but age was not found to account for a very significant portion of the total variation in screening values. These data are consistent with our approach to controlling pump seal emissions, which is based on random accidents, mistakes, or catastrophic seal failures causing pump seal leaks rather than gradual deterioration of the seals. Only a routine inspection program can quickly identify these unpredictable leaks for replacement. Routine seal replacements or infrequent seal inspections would not be as cost-effective because routine replacement would cause properly operating seals to be replaced with no emission reduction and because infrequent inspections would allow seals to remain leaking for long periods of time.

An analysis of the historical average length of time between seal replacements was also performed. It was found that the average length of time between seal replacement was 1 to 1 and 1/2 years and that 90 percent of the pump seals are replaced within 3 years. In the refinery leaks NSPS, we estimated that pump seals are routinely replacaed on the average every 2 years, which compares favorably with these findings.

LDAR Analysis - Several inputs for the LDAR model can be derived from the SCAQMD study of valves. These inputs were used, along with other necessary inputs as documented in the AID[3], to assess the cost effectiveness of additional controls for valves in SCAQMD refineries. The new inputs based on the SCAQMD study results are compared to the refinery NSPS inputs in Table 4. The initial percent leaking of 6.2 percent is the average for the five SCAQMD units tested. The emission factor was derived from this initial leak frequency using the leak/no leak emission factor calculation techniques developed in the AID. The leak occurrence rate is the average of the overall occurrence rates shown in Table 2. The emission reduction and repair rate are also from the SCAQMD study averages as discussed elsewhere in this memo.

Although the SCAQMD and NSPS inputs appear similar, the LDAR model was used to determine the extent to which the inputs could effect the cost effectiveness of routine monitoring programs. The complete inputs and outputs of this analysis are attached and the results are summarized in Table 5. As you can see, all of the cost effectiveness numbers are rather low, with the highest one, the incremental cost effectiveness of monthly over quarterly monitoring, less than 1000 $/Mg.

REFERENCES:

1. Evaluation of the Maintenance Effect on Fugitive Emissions From Refineries in the South Coast Air Quality Management District, EPA 600/7-82-049, December 1981.

2. Evaluation of Maintenance For Fugitive VOC Emission Control, EPA-600/2-81-080, May 1981.

3. Fugitive Emission Sources of Organic Compounds--Additional Information on Emissions, Emission Reductions, and Costs, EPA-450/3-82-010, April 1982.

4. VOC Fugitive Emissions in Petroleum Refining Industry--Background Information for Proposed Standards, EPA 450/3-81-015a, November 1982.

Attachments

cc: Fred Dimmick, SDB
Tom Rhoads, PES
Refinery Leaks Docket

TABLE 1. ESTIMATED RATE OF LEAK OCCURRENCE FOR SCAQMD VALVE DATA

PROCESS UNIT	DATE SCREENED	PERCENT LEAKING[a]	MONTHS BETWEEN TESTS	TEST-TO-TEST 30-DAY OCCURRENCE[b]	CUMULATIVE PERCENT LEAKING FROM BEGINNING OF TEST[c]	MONTHS FROM BEGINNING OF TEST	30-DAY OCCURRENCE FROM BEGINING OF TEST[d]
Alkylation	2/79	14.5	--	--	--	--	--
	7/79	5.4	5	0.93	5.4	5	0.93
	9/80	8.2	14	0.59	13.6	19	0.72
	2/81	9.0	5	1.80	22.6	24	0.94[e]
Isomax	4/79	2.6	--	--	--	--	--
	9/79	2.2	5	0.44	2.2	5	0.44
	10/80	3.6	13	0.28	5.8	18	0.32
	2/81	2.4	4	0.60	8.2	22	0.37[e]
FCCU	3/79	4.1	--	--	--	--	--
	8/79	1.2	5	0.24	1.2	5	0.24
	10/80	11.7	14	0.84	12.9	19	0.68
	2/81	6.6	4	1.65	19.5	23	0.85[e]
Crude Unit	11/79	1.5	--	--	--	--	--
	9/80	3.3	10	0.33	3.3	10	0.33
	3/81	2.3	6	0.38	5.6	16	0.35[e]
Platformer	11/79	8.2	--	--	--	--	--
	9/80	3.5	10	0.35	3.5	10	0.35
	3/81	5.9	6	0.98	9.4	16	0.59[e]

SOURCE: SCAQMD STUDY (Reference 1)

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[a] All but the last sreening test were performed by the refinery.

[b] Based on all leaks from the previous inspection being repaired and an assumption of linear leak occurrence, the leak frequency divided by the number of months between tests estimates the 30-day leak occurrence rate.

[c] Based on all leaks at initial inspection being repaired and assuming that if the other inspection had not occurred the leaks would have accumulated from inspection to inspection.

[d] Same methodology as discussed in footnote b except based on the initial inspection.

[e] These are the overall average monthly occurrence rates for the units studied.

TABLE 2. COMPARISON OF SCAQMD AND REFINERY NSPS OCCURRENCE RATES

PROCESS UNIT[a]	INITIAL LEAK FREQUENCY[a]	SCAQMD 30-DAY OCCURRENCE RATE[b]	REFINERY NSPS 30-DAY OCCURRENCE RATE
ALKYLATION	14.5	0.94	1.68
ISOMAX	2.6	0.37	0.52
FCCU	4.1	0.85	0.66
CRUDE UNIT	1.5	0.35	0.41
PLATFORMER	8.2	0.59	1.06

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[a] From SCAQMD study (Reference 1)

[b] From Table 1 - average 30 day occurrence rate from the beginning to the end of the test.

[c] Occurrence rate calculated as occ = 0.0976 x (initial leak frequency) + 0.264 based on a least squares analysis of the occurrence rates from the Maintenance study (Reference 2) as discussed in AID (Reference 3).

TABLE 3. REASONS VALVES WERE NOT SCREENED DURING RADIAN SCAQMD TESTING

SERVICE	NUMBER OF SOURCES	NUMBER SCREENED	PERCENT NOT SCREENED	PERCENT NOT SCREENED SPLIT BY REASONS NOT SCREENED*						
				1	2	3	4	5	6	7
Gas	2630	2337	11.1	--	3.3	7.3	0.04	0.4	0.04	--
Light Liquid	5677	4926	13.2	0.4	3.3	9.2	--	0.3	0.04	--
OVERALL	8307	7263	12.6	0.3	3.3	8.6	0.01	0.3	0.04	--

Source: SCAQMD Study (Reference 1)

*Reasons valves not screened:

1. Temporary factors such as sources taken out of service for repair.
2. Permanent factors such as sources that could not be reached without extraordinary aids.
3. Location, such as sources that could not be screened using the probe extension, but could be reached by using a stepladder.
4. High background concentration.
5. Accessible, but climbing not permitted.
6. Possible fouling of probe by visible leak to atmosphere.
7. Possible fouling of probe by visible leak to drain or sump.

TABLE 4. COMPARISON OF SCAQMD STUDY AND REFINERY NSPS LDAR INPUTS

PARAMETER	SCAQMD STUDY	REFINERY NSPS[a]
Emission Factor (kg/hr)	0.010[b]	0.0163
Monthly Leak Occurrence Rate (%)	0.6[c]	1.27
Initial Percent Leaking (%)	6.2	10.7
Emissions Reduction for Successful Repair (%)	95.7	97.7
Unsuccessful Repair Rate (%)	0.9	10

a - From Reference 4.

b - Calculated based on the average percent leaking and the leak/no leak technique developed in Reference 3.

c - Average occurrence rate from Table 2. The quarterly occurrence rate would be 3 times the monthly rate and the annual occurrence rate 4 times the quarterly rate.

TABLE 5. COST EFFECTIVENESS OF ROUTINE MONITORING BASED ON SCAQMD STUDY LDAR INPUTS

Monitoring Interval (Mo)	Emission Reduction (percent)	Emission Reduction (Mg/yr)	Net Cost ($/yr)	Cost Effectiveness ($/Mg)
12	20.7	18.1	- 407	- 23
3	47.9	42	-2870	- 68
1	54.5	47.8	2580	54
12-3[a]	27.2	23.9	-2463	-103
12-1[a]	33.8	29.7	2987	100
3-1[a]	6.6	5.8	5450	940

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a - These denote the incremental emission reduction, cost, and cost effectiveness between the two monitoring intervals shown.

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                              I N P U T   D A T A

                                   PLANT SCV
                          (FOR GELL ANNUAL VALVES )


FOR EXAMINING EMISSION REDUCTIONS DUE TO LDAR:
_____________________________________________

     MONITORING INTERVAL (MONTHS)                                    12
     TURNAROUND FREQUENCY (MONTHS)                                   24
     EMISSION FACTOR (KG/HR/SOURCE)                                0.01
     LEAK OCCURRENCE RATE (% PER PERIOD)                            7.4
     INITIAL % LEAKING                                              6.2
     EMISSIONS REDUCTION FOR UNSUCCESSFUL REPAIR (%)               62.6
     EMISSIONS REDUCTION FOR SUCCESSFUL REPAIR (%)                 95.7
     EARLY LEAK RECURRENCE (% OF REPAIRS)                          14.0
     UNSUCCESSFUL REPAIR RATE (%)                                   0.9
     UNSUCCESSFUL REPAIR RATE (%) AT TURNAROUND                     0.0

FOR EXAMINING THE COSTS OF LDAR:
________________________________

     TOTAL NUMBER OF SOURCES                                      1,000
     MONITORING TIME PER SOURCE INSPECTION (MINUTES)                2.0
     VISUAL MONITORING TIME PER SOURCE (MINUTES)                   0.00
     NUMBER OF VISUAL INSPECTIONS PER YEAR                            0
     REPAIR TIME PER SOURCE (MINUTES)                                68
     LABOR RATE ($/HOUR)                                             18
     PARTS COST PER SOURCE ($)                                        0
     ADMINISTRATIVE & SUPPORT OVERHEAD COST FACTOR (%)             40.0
     CAPITAL RECOVERY FACTOR (%)                                   16.3
     RECOVERY CREDIT FOR EMISSIONS REDUCTION ($/MG)                 215
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                        I N P U T   D A T A

                              PLANT SCV
                       (FOR G&LL MONTHLY VALVES )


FOR EXAMINING EMISSION REDUCTIONS DUE TO LDAR:
_____________________________________________

     MONITORING INTERVAL (MONTHS)                                  1
     TURNAROUND FREQUENCY (MONTHS)                                24
     EMISSION FACTOR (KG/HR/SOURCE)                             0.01
     LEAK OCCURRENCE RATE (% PER PERIOD)                         0.6
     INITIAL % LEAKING                                           6.2
     EMISSIONS REDUCTION FOR UNSUCCESSFUL REPAIR (%)            62.6
     EMISSIONS REDUCTION FOR SUCCESSFUL REPAIR (%)              95.7
     EARLY LEAK RECURRENCE (% OF REPAIRS)                       14.0
     UNSUCCESSFUL REPAIR RATE (%)                                0.9
     UNSUCCESSFUL REPAIR RATE (%) AT TURNAROUND                  0.0

FOR EXAMINING THE COSTS OF LDAR:
________________________________

     TOTAL NUMBER OF SOURCES                                   1,000
     MONITORING TIME PER SOURCE INSPECTION (MINUTES)             2.0
     VISUAL MONITORING TIME PER SOURCE (MINUTES)                0.00
     NUMBER OF VISUAL INSPECTIONS PER YEAR                         0
     REPAIR TIME PER SOURCE (MINUTES)                             68
     LABOR RATE ($/HOUR)                                          18
     PARTS COST PER SOURCE ($)                                     0
     ADMINISTRATIVE & SUPPORT OVERHEAD COST FACTOR (%)          40.0
     CAPITAL RECOVERY FACTOR (%)                                16.3
     RECOVERY CREDIT FOR EMISSIONS REDUCTION ($/MG)              215
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                              I N P U T   D A T A

                                   PLANT SCV
                          (FOR GELL QUATERLY VALVES )


FOR EXAMINING EMISSION REDUCTIONS DUE TO LDAR:
____________________________________________

     MONITORING INTERVAL (MONTHS)                                      3
     TURNAROUND FREQUENCY (MONTHS)                                    24
     EMISSION FACTOR (KG/HR/SOURCE)                                 0.01
     LEAK OCCURRENCE RATE (% PER PERIOD)                             1.9
     INITIAL % LEAKING                                               6.2
     EMISSIONS REDUCTION FOR UNSUCCESSFUL REPAIR (%)                62.6
     EMISSIONS REDUCTION FOR SUCCESSFUL REPAIR (%)                  95.7
     EARLY LEAK RECURRENCE (% OF REPAIRS)                           14.0
     UNSUCCESSFUL REPAIR RATE (%)                                    0.9
     UNSUCCESSFUL REPAIR RATE (%) AT TURNAROUND                      0.0

FOR EXAMINING THE COSTS OF LDAR:
________________________________

     TOTAL NUMBER OF SOURCES                                       1,000
     MONITORING TIME PER SOURCE INSPECTION (MINUTES)                 2.0
     VISUAL MONITORING TIME PER SOURCE (MINUTES)                    0.00
     NUMBER OF VISUAL INSPECTIONS PER YEAR                             0
     REPAIR TIME PER SOURCE (MINUTES)                                 68
     LABOR RATE ($/HOUR)                                              18
     PARTS COST PER SOURCE ($)                                         0
     ADMINISTRATIVE & SUPPORT OVERHEAD COST FACTOR (%)              40.0
     CAPITAL RECOVERY FACTOR (%)                                    16.3
     RECOVERY CREDIT FOR EMISSIONS REDUCTION ($/MG)                  215
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PLANT SCV SUMMARY:

AVERAGE ANNUAL COST EFFECTIVENESS
(YEARLY LDAR)

SOURCE TYPE	EMISSION REDUCTION (MG/YR)	RECOVERY CREDIT	NET COSTS	GROSS COST EFFECTIVENESS (PER MG)	NET COST EFFECTIVENESS (PER MG)
VALVES					
G&LL ANNUAL	18.1	$ 3,890	$ -407	$ 193	$ -23
G&LL MONTHLY	47.8	10,300	2,580	269	54
G&LL QUATERLY	42	9,030	-2,870	147	-68
PLANT TOTAL	108	$ 23,200	$ -692	$ 209	$ -6

APPENDIX D

MODEL UNIT AND NATIONWIDE IMPACTS

Attached as Appendix D is a memorandum dated December 13, 1983 that documents the calculation of model units and nationwide impacts of the promulgated standards.

A-80-44
IV-B-24

MEMORANDUM

DATE: December 13, 1983

TO: Docket A-80-44, Petroleum Refinery VOC Fugitive Emissions NSPS

FROM: Thomas Rhoads, Pacific Environmental Services, Inc. TWR

SUBJECT: Calculation of Model Unit and Nationwide Impacts

This memorandum documents the calculation of the capital cost, net annualized cost, and emission reduction resulting from implementation of the standards. The impacts are presented for each model unit on a yearly basis and nationwide in the fifth year of implementation of the standards. The basis and method for calculating the model unit and nationwide impacts are from the background information documents for the proposed standards and promulgated standards.

Tables 1 and 2 show model unit and nationwide emission reductions achieved between baseline and uncontrolled scenarios. Uncontrolled means the level of control implemented by refineries in the absence of any regulations to control equipment leaks of VOC. Baseline, however, reflects a nationwide average level of control implemented as a result of existing regulations (i.e., State and regional) to control equipment leaks of VOC. Tables 3 and 4 show model unit and nationwide emission reductions resulting from implementation of the final standards as the increment between baseline emissions and the level of emissions following promulgation of the standards. As shown in Table 4, 31,100 Mg VOC emission reduction would be achieved in the fifth year of implementation of the final standards. The cost impacts of the final standards, likewise, do not include the baseline product recovery credits and costs for monitoring instruments (those costs incurred by the industry due to existing regulations). Net annualized costs to implement the final standards are derived in Tables 6, 7, and 8. Implementation of the final standards would cost approximately $4.14 million (1980 dollars) with a cost effectiveness, therefore, of about $130/Mg VOC emission reduction. The cumulative nationwide capital costs, calculated in Tables 8 and 9, are projected at about $17.9 million in the fifth year of implementation of the final standards.

Table 1. MODEL UNIT EMISSION REDUCTION BETWEEN BASELINE AND UNCONTROLLED

Equipment	Control	Regulatory Alternative II Emission Reduction per Component (Mg/yr)[a]	Regulatory Alternative II Model Unit Emission Reduction (Mg/yr)[b]					
			A		B		C	
			Components	Subtotal	Components	Subtotal	Components	Subtotal
Pressure Relief Devices	Quarterly LDR	0.63	3	1.9	7	4.4	20	12.6
Compressors	Quarterly[c] LDR	4.3	1	4.3	3	12.9	8	34.4
Open Ended Lines	Cap	0.020	70	1.4	140	2.8	420	8.4
Sampling Connections	No Control	0	10	0	20	0	60	0
Valves								
Gas	Quarterly LDR	0.14	130	18.2	260	36.4	780	109
Light Liquid	Annual[d] LDR	0.019	250	4.8	500	9.5	1,500	28.5
Pumps	Annual LDR	0.21	7	1.5	14	2.9	40	8.4
Total Emission Reduction Regulatory Alternative II (Mg/yr)				32.1		68.9		201
Baseline Emission Reduction (Mg/yr)[e]				18.0		38.6		113

LDR = leak detection and repair

Footnotes on next page

Table 1. MODEL UNIT EMISSION REDUCTION BETWEEN BASELINE AND UNCONTROLLED (concluded)

[a] From BID for the promulgated standards, Appendix A, pages A-4, 7, 8, 9, 10, and 14.

[b] Model unit equipment counts are found in Table 6-1 of the BID for the proposed standards. The model unit emission reductions are obtained by summing the products obtained from the per component emission reductions and the number of components per model unit.

[c] From Table 7-1, BID for the proposed standards. Uncontrolled emission factor = 15.0 kg/d. Controlled emission factor for quarterly LDR = 3.2 kg/d.

$$\begin{array}{ll}\text{Emission} & = (15.0\ \text{kg/d} - 3.2\ \text{kg/d})\ (365\ \text{d/yr})\left(\frac{1\ \text{Mg}}{1000\ \text{kg}}\right) \\ \text{Reduction} & \quad = 4.3\ \text{Mg/yr}\end{array}$$

[d] From Table F-3, BID for the proposed standards. Uncontrolled emission factor = 0.26 kg/d
Controlled emission factor for annual LDR = 0.209 kg/d

$$\begin{array}{ll}\text{Emission} & = (0.26\ \text{kg/d} - 0.209\ \text{kg/d})\ 0.365 \\ \text{Reduction} & \quad = 0.019\ \text{Mg/yr}\end{array}$$

[e] Baseline emission reduction is achieved by industry using existing levels of control. About 44 percent of the petroleum refining industry is located in attainment areas for ozone and not subject to equipment leak regulations (uncontrolled), and about 56 percent is located in non-attainment areas and subject to State or local regulations (Regulatory Alternative II). Baseline emission reduction is, therefore, calculated as 56 percent of the emission reduction achieved under Regulatory Alternative II.

Table 2. NATIONWIDE EMISSION REDUCTION BETWEEN BASELINE AND UNCONTROLLED

Model Unit	Emission Reduction Per Model Unit (Mg/yr)[a]	Projected Model Units[b]	Subtotal (Mg/yr)
A	18.0	96	1,730
B	38.6	106	4,090
C	113	80	9,040
		TOTAL	14,900

[a] Emission reductions from Table 1.

[b] From BID for the proposed standards, Table 7-4.

Table 3. MODEL UNIT EMISSION REDUCTION BETWEEN NSPS AND BASELINE

Equipment	Control	Emission Reduction Per Component Between NSPS and Uncontrolled (Mg/yr)[a]	Emission Reduction by Model Unit (Mg/yr)					
			A		B		C	
			Components	Subtotal	Components	Subtotal	Components	Subtotal
Pressure Relief Devices	Disk	1.4	3	4.2	7	9.8	20	28.0
Compressors	Barrier Fluid System	5.5	1	5.5	3	16.5	8	44.0
Open Ended Lines	Cap	0.020	70	1.4	140	2.8	420	8.4
Sampling Connections	Closed Purge	0.13	10	1.3	20	2.6	60	7.8
Valves	Monthly LDR	0.10	380	38.0	760	76.0	2,280	228
Pumps	Monthly LDR	0.82	7	5.7	14	11.5	40	32.8
Emission Reduction From Uncontrolled to NSPS				56.1		119		349
Emission Reduction From Uncontrolled to Baseline[b]				18.0		38.6		113
Emission Reduction From Baseline to NSPS[c]				38.1		80.4		236

[a] From BID for the promulgated standards Appendix A, pages A-4, 7, 8, 9, 10, and 14.

[b] From Table 1.

[c] Represents emission reduction per model unit resulting from promulgation of the standards.

Table 4. NATIONWIDE EMISSION REDUCTION BETWEEN NSPS AND BASELINE

Model Unit	Emission Reduction Per Model Unit (Mg/yr)[a]	Projected Model Units[b]	Subtotal (Mg/yr)
A	38.1	96	3,660
B	80.4	106	8,520
C	236	80	18,900
		Total	31,100

[a] Emission reductions from Table 3.

[b] From BID for the proposed standards, Table 7-4.

Table 5. MODEL UNIT NET ANNUALIZED COST BETWEEN BASELINE AND UNCONTROLLED

Equipment	Control	Net Annualized Cost Per Component Between Regulatory Alternative II and Uncontrolled[a] ($/yr)	Regulatory Alternative II Net Annualized Cost Per Model Unit ($/yr)					
			A		B		C	
			Components	Subtotal	Components	Subtotal	Components	Subtotal
Pressure Relief Devices	Quarterly LDR	(170)	3	(510)	7	(1,190)	20	(3,400)
Compressors[b]	Quarterly[c] LDR	(690)	1	(690)	3	(2,070)	8	(5,520)
Open Ended Lines	Cap	9.1	70	637	140	1,270	420	3,820
Sampling Connections	No Control	0	10	0	20	0	60	0
Valves								
Gas[c]	Quarterly LDR	(21)	130	(2,730)	260	(5,460)	780	(16,400)
Light[d] Liquid	Annual[d] LDR	2.04	250	510	500	1,020	1,500	3,060
Pumps	Annual LDR	180	7	1,260	14	2,520	40	7,200
Regulatory Alternative II Costs Without Instruments				(1,520)		(3,910)		(11,200)
Regulatory Alternative II Costs With Instruments[e]				3,980		1,590		(5,700)
Net Annualized Cost Between Baseline and Uncontrolled[f]				2,230		890		(3,190)

LDR = leak detection and repair
( ) = cost savings

[a] Regulatory Alternative II costs per component are from the BID for promulgated standards Appendix A, pages A-4, 7, 8, 11, and 15.

Table 5. MODEL UNIT NET ANNUALIZED COST BETWEEN BASELINE AND UNCONTROLLED (continued)

[b] Quarterly leak detection and repair for compressors, from BID for the proposed standards, Table F-12.

$$\text{Initial leak repair} = \begin{pmatrix}\text{Initial}\\ \text{Leak}\\ \text{Frequency}\end{pmatrix} \begin{pmatrix}\text{Repair}\\ \text{Time}\end{pmatrix} \begin{pmatrix}\text{Labor}\\ \text{Rate}\end{pmatrix} \begin{pmatrix}\text{Over-}\\ \text{Head}\end{pmatrix} \begin{pmatrix}\text{Capital}\\ \text{Recovery}\\ \text{Factor}\end{pmatrix}$$

$$= (0.35)\ (40\text{ hrs})\ (\$18/\text{hr})\ (1.4)\ (0.163)$$

$$= \$57.50$$

$$\text{Monitoring Labor} = (\text{Monitoring labor hours})\ (\text{Labor rate}) = (1\text{ hr})\ (\$18/\text{hr})$$

$$= \$18$$

$$\text{Repair Labor} = (\text{Repair Labor hours})\ (\text{Labor rate}) = 6\text{ hr}\ (\$18/\text{hr}) = \$108$$

$$\begin{array}{l}\text{Administrative}\\ \text{and Support}\end{array} = 0.4 \begin{pmatrix}\text{Monitoring} & & \text{Repair}\\ \text{Labor} & + & \text{Labor}\end{pmatrix} = 0.4\ (18 + 108) = \$50.40$$

TOTAL ANNUALIZED COST = $234

RECOVERY CREDIT = ($215/Mg) (4.3 Mg/yr) = $924

NET ANNUALIZED COST per compressor = is a cost savings of $690

[c] Gas Service Valves, from BID for promulgated standards Table A-6.

[d] Light Liquid Service Valves, from BID for proposed standards Table F-27.

$$\text{Initial Leak Repair} = \begin{pmatrix}\text{Initial leak}\\ \text{Frequency}\end{pmatrix} \begin{pmatrix}\text{Repair}\\ \text{Time}\end{pmatrix} \begin{pmatrix}\text{Labor}\\ \text{Rate}\end{pmatrix} \begin{pmatrix}\text{Over-}\\ \text{head}\end{pmatrix} \begin{pmatrix}\text{Capital}\\ \text{Recovery}\\ \text{Factor}\end{pmatrix}$$

$$= (0.11)\ (1.13\text{ hr})\ (\$18/\text{hr})\ (1.4)\ (0.163) = \$0.51$$

$$\text{Monitoring Labor} = \begin{pmatrix}\text{Fraction of}\\ \text{Sources}\\ \text{Screened}\end{pmatrix} \begin{pmatrix}\text{Monitoring}\\ \text{Time}\end{pmatrix} \begin{pmatrix}\text{Labor}\\ \text{Rate}\end{pmatrix}$$

$$= (0.99)\ (1/60\text{ hr})\ (\$18/\text{hr})\ (2) = \$0.59$$

$$\text{Repair Labor} = \begin{pmatrix}\text{Fraction of}\\ \text{Sources}\\ \text{Operated on}\end{pmatrix} \begin{pmatrix}\text{Repair}\\ \text{Time}\end{pmatrix} \begin{pmatrix}\text{Labor}\\ \text{Rate}\end{pmatrix}$$

$$= 0.168\ (1.13)\ (\$18) = \$3.42$$

Table 5. MODEL UNIT NET ANNUALIZED COST BETWEEN BASELINE AND UNCONTROLLED (concluded)

$$\text{Administrative and Support} = 0.4 \left(\begin{array}{l}\text{Monitoring} \\ \text{Labor}\end{array} + \begin{array}{l}\text{Repair} \\ \text{Labor}\end{array} \right)$$

$$= 0.4\ (\$0.59 + \$3.42) = \$1.60$$

TOTAL ANNUALIZED COST = $6.12

RECOVERY CREDIT = (0.019/Mg/yr) ($215) = $4.08

NET ANNUALIZED COST = $2.04 per valve

[e] Annualized instrument cost from BID for the proposed standards, Tables 8-1 and 8-5. Annualized cost = Capital recovery Cost + Maintenance Cost + Miscellaneous Cost.

$$\text{Capital Recovery Cost} = \left(\$9{,}200/\text{Model Unit} \right) \times \left(\begin{array}{l}\text{Capital} \\ \text{Recovery Factor}\end{array} \right)$$

$$= \$9{,}200/\text{unit} \times 0.23$$

$$= \$2{,}100/\text{unit}$$

Maintenance Cost = $3,000

Miscellaneous Cost = 0.04 x $9,200 = $368

Total = $5,500/model unit

[f] See footnote e from Table 1. Baseline costs = 0.56 x Regulatory Alternative II.

Table 6. MODEL UNIT NET ANNUALIZED COSTS BETWEEN NSPS AND BASELINE

Equipment	Control	Net Annualized Costs From Uncontrolled To NSPS ($/yr)[a]	Net Annualized Cost Per Model Unit					
			A		B		C	
			Components	Subtotal	Components	Subtotal	Components	Subtotal
Pressure Relief Devices	Rupture Disk	580	3	1,740	7	4,060	20	11,600
Compressors	Barrier Fluid System	840	1	840	3	2,520	8	6,720
Open Ended Lines	Cap	9.1	70	637	140	1,270	420	3,820
Sampling Connections	Closed Purge	105	10	1,050	20	2,100	60	6,300
Valves	Monthly LDR	(6)	380	(2,280)	760	(4,560)	2,280	(13,700)
Pumps	Monthly LDR	130	7	910	14	1,820	40	5,200
Costs from Uncontrolled to NSPS w/o Instrument				2,900		7,210		20,000
Costs from Uncontrolled to NSPS with Instrument[b]				8,400		12,700		25,500
Costs from Uncontrolled to Baseline[c]				2,230		890		(3,190)
Costs from Baseline to NSPS[d]				6,170		11,800		28,700

LDR = leak detection and repair
( ) = cost savings

[a] The basis for the control costs for the individual components represent the costs from uncontrolled to the control required by the standards. From Appendix A of the BID for the promulgated standards, pages A-4, 7, 8, 11, and 15.

[b] See footnote e of Table 5.

[c] From Table 5.

[d] Represents model unit net annualized costs between NSPS and baseline.

Table 7. NATIONWIDE NET ANNUALIZED COSTS FROM BASELINE TO NSPS

Model Unit	Net Annualized Cost Per Model Unit ($/yr)[a]	Projected Model Units[b]	Subtotal (Mg/yr)
A	6,170	96	592,000
B	11,800	106	1,250,000
C	28,700	80	2,300,000
		Total	4,140,000

[a] Net Annualized Costs per model unit from Table 6.

[b] From BID for the proposed standards, Table 7-4.

Table 8. MODEL UNIT CAPITAL COSTS

Control	Model Unit Capital Cost ($)		
	A	B	C
Regulatory Alternative II[a]	13,000	17,000	31,000
Baseline[b]	7,280	9,520	17,400
NSPS (from uncontrolled)			
New Unit[c]	35,000	73,000	190,000
Modified/Reconstructed[d] Unit	39,000	81,000	210,000
NSPS (from Baseline)[e]			
New Unit	27,700	63,500	173,000
Modified/Reconstructed Unit	31,700	71,500	193,000

[a] From BID for the proposed standards, Table 8-2.

[b] See footnote e of Table 1. Calculated as 56 percent of Regulatory Alternative II. Baseline capital costs are incurred by industry using existing levels of control and, therefore, represents a weighted average between uncontrolled (no cost) and Regulatory Alternative II, not the actual capital cost incurred by an individual model unit.

[c] From BID for the proposed standards, Table 8-12. Regulatory Alternative II capital costs are the same as that for the standards.

[d] From BID for the proposed standards, Table 8-13, corrected to include closed loop sampling under Regulatory Alternative III.

[e] Calculated as the capital cost from uncontrolled to NSPS minus baseline capital costs. Represents capital cost incurred per model unit regulting from promulgation of the standards.

Table 9. NATIONWIDE CAPITAL COSTS

New Units				Modified/Reconstructed Units			
Model Unit	Projected Model Units[d]	Capital Cost Per Model Unit[b] ($)	Subtotal ($)	Model Unit	Projected Model Units[a]	Capital Cost Per Model Units[b]	Subtotal ($)
A	49	27,700	1,360,000	A	47	31,700	1,490,000
B	27	63,500	1,710,000	B	79	71,500	5,650,000
C	24	173,000	4,150,000	C	56	193,000	10,800,000
		Total	7,220,000			Total	17,900,000

[a] From BID for the proposed standards, Table 7-4.

[b] From Table 8.